Distribution Pricing Reform: Next steps

7 May 2024

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

Distribution networks play a critical role in the electrification of New Zealand's economy. Increased electrification will lead to a substantial increase in electricity demand and is likely to require substantial investment in distribution networks. Optimising that investment is important to secure a more affordable transition for consumers and deliver our goals around a net-zero carbon future by 2050.

The Electricity Authority Te Mana Hiko is committed to improving distribution pricing to help deliver better outcomes for consumers. Getting distribution pricing right helps manage how much traditional investment (such as poles and wires) is required, and ensures investment in new technology happens in the right place on the network.

Distribution pricing helps existing network users, individuals or organisations seeking a network connection (access seekers) and distributors choose how they invest in and use the network. Cost-reflective distribution pricing guides usage and investment toward better outcomes for consumers, such as more efficient use of the network and lower network costs per unit of energy.

We want distribution pricing to send the right signals about the cost of the electricity that's being fed to homes and businesses. Accurate price signals will encourage better use of the electricity network, motivating consumers and businesses to consider using new technologies to manage congestion when the network is fully used (such as in the evenings during the middle of winter). Over time, this means distributors should spend less in total on new investments and grid maintenance, keeping overall distribution costs lower for consumers.

This paper outlines next steps after receiving feedback on our July 2023 issues paper

We published an issues paper in July 2023 that examined five key topics and high-level options for addressing each topic. Having considered feedback and analysed the situation, we have reached a view on next steps. These are set out in this update.

We will work with industry on a draft Code amendment to regulate connection pricing

We have decided to develop, for consultation, a draft Code amendment to mandate efficient connection pricing. We are concerned that inefficiently high upfront charges will act as a barrier to access seekers looking for the best option to connect to the network or existing consumers wanting to upgrade their connections. This could result in consumers losing out on the benefits of new investment and services (such as vehicle charging, heating electrification and more affordable new housing).

On the other hand, we do not want to see upfront charges set so low that existing consumers have to pick up the bill for additional or upgraded connections. Access seekers' upfront and ongoing payments should at least cover the costs they add to the network. This will ensure existing consumers are not made worse off and incentivise access seekers to ensure their connections are efficiently sized and configured.

Some distributors have significantly increased their upfront charges in recent years, and further increases are possible. In part, this reflects distributors looking to manage the financing of their network investment programmes. Financeability is a concern for some distributors in the face of high interest costs and growing capital expenditure programmes. We want to ensure this does not drive distributors to adopt inefficient connection pricing

methodologies. We are engaging closely with the Commerce Commission (the Commission) to ensure any decisions we make align with the Commission's price-quality regulation.

We have carefully considered all submissions, including those from distributors who propose regulation only if a voluntary approach is unsuccessful and propose additional guidance as a first step.

We consider distribution pricing reform to be urgent, given the pace and scale of investment necessary to enable electrification. Our focus is on ensuring consumers benefit from investment across the electricity system and have access to affordable electricity solutions for generations to come, and we do not consider guidance on connection pricing would enable quick and enduring change for the benefit of all consumers.

For this reason, we are focusing resources on working with industry to develop a Code amendment on connection pricing. We will seek input from interested stakeholders through a technical group that will work with us to develop a Code amendment for consultation in late 2024.

We will assess the impact of proposed amendments, being mindful of effects on consumers, including those in hardship. We also plan to consider the impact on distributor financing. Following consultation, if we decide to amend the Code, the amendment would be implemented over a timeline that enables coordination with the Commission's price-quality regulation.

We will refine our guidance on more efficient peak and off-peak price signals

We will refine our guidance to distributors and our approach to pricing scorecards to encourage more efficient peak and off-peak price signals. We will focus on guidance in 2024 (including an open letter to distributors) and then resume our assessment of pricing methodologies via the scorecards process in 2025. Our approach in 2025 and beyond will be informed by the distributors' progress.

We will monitor assignment to time-varying distribution tariffs and use of metered data

Submissions clearly supported greater assignment of installation control points (ICPs) to time-varying distribution tariffs, such as Time of Use (TOU) tariffs. Some distributors have made good progress, and we encourage further work in this area. We will monitor the assignment of ICPs to time-varying distribution tariffs and engage with individual distributors on their progress.

We are still considering how best to support the transition to distributors billing retailers based on metered data on consumption by time of use where possible. As a next step, we will seek data from the industry over the coming months to inform our thinking on this matter.

We are still assessing target revenue allocation

Target revenue allocation is a developing area. Key concepts, such as the subsidy-free range, need further development to ensure a clear industry-wide understanding from which we can progress toward testing the efficiency of target revenue allocations.

We will consult later in the year

This is an update paper, and we are not seeking submissions in response. We will be seeking submissions from stakeholders later in 2024, when we expect to release a proposed Code amendment on connection pricing for consultation.

Contents

1. Introduction

1.1. The purpose of this paper is to provide an update on how the Electricity Authority Te Mana Hiko (the Authority) will progress its Targeted Reform of Distribution Pricing programme (the targeted reform programme).

1.2. We published an issues paper in July 2023 that examined five key issues:

(a) connection pricing – setting efficient upfront charges (including capital contributions) for access seekers (individuals or organisations seeking a network connection)

(b) peak period price signals – signalling the cost consequences of network use during peak periods

(c) off-peak price signals – avoiding deterring network use during off-peak periods

(d) retailer response – ensuring retailers are incentivised to manage distribution input costs (for example, through flexibility services and retail pricing structures)

(e) target revenue allocation – efficiently allocating costs between consumer groups.

1.3. The issues paper explored three broad regulatory options to promote faster and more consistent pricing reform. The three options were:

(a) continuation – continue to influence pricing through pricing principles, guidance (for example, distribution pricing practice note) and scorecards

(b) control – mandate or prohibit (via Code amendments) certain pricing approaches (for example, place an upper limit on connection charges)

(c) call-in – in the Code, provide the Authority with the ability for targeted call-in to review and approve specific aspects of a distributor's methodology that are outliers in some sense.

1.4. We received 52 submissions and cross-submissions on the issues paper, and we ran four forums that attracted 80 participants. We thank stakeholders for the useful insights they have provided and look forward to further high-quality engagement in coming months.

1.5. Having considered the submissions and engagement feedback, and carried out further analysis, we have reached a view on next steps for each of the five issues.

1.6. The balance of this paper provides further context on our target reform programme, then steps through each of the five issues in more detail. For each issue we:

(a) recap relevant context

(b) provide a statement of the current situation/problem

(c) recap the options proposed in our issues paper

(d) summarise submissions

(e) outline our intended next steps.

2. Background and context for the targeted reform programme

2.1. Electrification unlocks significant benefits to consumers and the wider economy. Electrification allows consumers to take charge of their energy use, through controllable technology and load-management tools that can respond dynamically to changing network conditions. This ultimately leads to efficient network investment and lower power bills over time. Electrification of industrial processes and transport reduces reliance on fossil fuels and opens the economy to decarbonisation by increasing the use of our country's already highly renewable generation capacity.

2.2. Electrifying public and private transport, space and water heating, and process heat will lead to a substantial increase in electricity demand during the transition to a lower-emissions future. Much of this transition will occur at the distribution network level, with:

(a) new and upgraded connections for electric vehicle charging, including for public transport, private vehicle fleets, commercial services (including airlines) and public charging facilities

(b) new and upgraded connections for process heat conversions as coal and gas boilers are replaced with electric energy sources

(c) changes in electricity usage at existing connections, including as households convert from gas to electric water heating and start charging electric vehicles at home

(d) investment in control systems and batteries adding distributed flexibility into the system.

2.3. Efficient distribution pricing has a crucial role to play in guiding investment and usage patterns through this transition, ensuring the best outcomes for consumers.

2.4. Distribution pricing should signal the consequences of network usage on cost while avoiding deterring usage that does not add to costs. We refer to this as 'cost-reflective pricing'. Cost-reflective pricing helps guide usage and investment toward more optimal outcomes, for example, reduced need for costly network upgrades, better network utilisation and lower cost per unit of energy.

2.5. Efficient connection pricing strikes a balance between sending cost-reflective signals to access seekers, supporting efficient connection growth and encouraging distributors toward efficient network planning, investment and operation.

(a) Upfront charges that are too high have a dampening effect on connection growth, slowing down electrification activities.

(b) High upfront charges can also make it harder for distributors to plan ahead for efficient capacity upgrades and to coordinate anticipatory capacity.

(c) Cost-reflective charges encourage new users to make trade-offs between cost and quality (including capacity, configuration and security).

2.6. We are responsible for pricing methodologies for transmission and distribution services[1] and are committed to ensuring distribution pricing reforms occur in a timely manner. We have promoted distribution pricing reforms since 2019 by publishing updated distribution pricing principles, providing ongoing guidance and using scorecards to assess distributors' performance.

2.7. Our Targeted Reform of Distribution Pricing work programme takes stock of distribution pricing reform priorities for the energy transition and identifies any additional regulatory interventions we consider necessary or desirable.

2.8. We are focused on delivering benefit to all electricity consumers. This work aligns with our main statutory objective to promote competition in, reliable supply by and the efficient operation of the electricity industry for the long-term benefit of consumers. Targeted distribution pricing reform will unlock investment and innovation, promoting competition and supporting a more reliable and efficient electricity industry.

Developments since the issues paper

2.9. Thank you to everyone who submitted.

(a) We received 40 submissions and 12 cross-submissions on our issues paper, with 62% providing substantive comment on connection pricing.

(b) We discussed specific issues at four forums held during consultation. These forums covered various issues, including connection pricing.[2]

2.10. We also received substantive input on other topics in the forums and through submissions. In addition, there have been various developments across the electricity sector that are relevant to some of the matters raised in the issues paper.

(a) *2023 pricing scorecards and information paper*[3] – We completed and published our 2023 scorecards and a companion information paper in October 2023. There has been good progress overall, and we believe we can best support further progress at this time in areas of peak and off-peak signalling, retailer response and target revenue allocation through engagement and guidance.

(b) The *regulatory settings work programme*[4] – Also in October 2023, we published our indicative work programme for distribution network settings. This includes initiatives related to matters covered in our issues paper, including work on non-price barriers to network connection. We have commenced work on Code development and amendments to improve connection processes for large capacity load and distributed generation. This work is complementary to work on connection pricing.

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1 We are responsible by way of our power to set distributor pricing methodologies under section 32(4)(b) of the Electricity Industry Act 2010. The Commerce Commission New Zealand is also responsible for pricing regulation through its Information Disclosure regime and revenue for non-exempt electricity distribution businesses (EBDs) subject to price-quality regulation under Part 4 of the Commerce Act 1986.

2 For a summary of stakeholder feedback across the forums, see our Distribution Pricing Reform Forum slides at: www.ea.govt.nz/documents/3940/Distribution_pricing_forums_-_Presentation_slides.pdf

3 Distribution pricing | Electricity Authority (ea.govt.nz)

4 Updating regulatory settings for distribution networks | Our projects | Electricity Authority (ea.govt.nz)

(c) The final report on *price discovery in a renewables-based electricity system*[5] – The Market Development Advisory Group (MDAG) published its final report in December 2023. While the report focuses on wholesale market design issues, it has crossover with distribution pricing in the areas of retail market monitoring, use of half-hourly metering data and longer-term arrangements for coordinating distributed energy resources.[6] These recommendations are relevant to our consideration of retail pass-through and longer-term evolution of congestion price signalling.

(d) *The Commerce Commission's final decision on the input methodologies review*[7] –The Commission completed its 2023 review of the rules it uses to regulate distribution businesses. The review includes final decisions on default price-quality path (DPP) reopeners, the introduction of the large customer contract (LCC) mechanism and customised price-quality path (CPP) rules. These decisions are relevant to our work on connection pricing because restricting reliance on upfront charges may increase some distributors' regulated expenditure net of capital contributions – potentially directly (that is, increased net connection and system growth capital expenditure, (CapEx) and indirectly (that is, changes to system growth CapEx or operating expenses, OpEx, plans).

(e) *2025 revenue reset process* – The Commission is working toward a November 2024 decision on DPPs for the four to five years starting April 2025.[8] Since our issues paper, the Commission has held workshops on capital expenditure and innovation and published an issues paper on the financeability of electricity distribution services in the default price-quality path[9]. It has also gathered updated expenditure forecasts from all distributors. This process is a rich source of sector information and will lead to determinations that will be relevant to implementing any Code amendments that restrict upfront funding.

(f) *Electricity Networks Aotearoa (ENA)* – ENA has developed a centralised webpage for connection pricing information.[10] The page includes links to summary sheets and connection policies for each distributor and an interactive map.

(g) *Matters relating to connection pricing included in the Government's coalition agreements* – The feature of these matters in the Government's coalition

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5 Pricing in a renewables-based electricity system | Our projects | Electricity Authority (ea.govt.nz)

6 See MDAG recommendations 3, 4, 5, 18, and 19 in: Price discovery in a renewables-based electricity system: Final recommendations paper 2023 (ea.govt.nz), 11 December 2023.

7 See the Commerce Commission's webpage 2023 Input Methodologies Review at: https://comcom.govt.nz/regulated-industries/input-methodologies/input-methodologies-for-electricity-gas-and-airports/input-methodologies-projects/2023-input-methodologies-review

8 See the Commerce Commission's webpage 2025 reset of the electricity default price-quality path at: https://comcom.govt.nz/regulated-industries/electricity-lines/projects/2025-reset-of-the-electricity-default-price-quality-path

9 Commerce Commission New Zealand. *DPP4 reset – Financeability of electricity distribution services in the default price-quality path: Issues paper*. 22 February 2024. URL: https://comcom.govt.nz/__data/assets/pdf_file/0026/344168/DPP4-reset-Financeability-of-electricity-distribution-services-in-the-default-price-quality-Issues-paper-22-February-2024.pdf (accessed 20 April 2024).

10 See the ENA's webpage EDB connection factsheets and contribution policies at: https://ena.org.nz/resources/connection-map/

agreements signal that connection pricing has gained wider prominence as an issue at various levels of government.[11]

(h) Our *retail monitoring project*[12] – We recently consulted on a proposal to streamline and extend our retail market information gathering. The new information gathered would include more detail on tariffs and billing, which would help us better understand retailer responses, particularly in terms of the availability and consumer uptake of non-uniform time-varying retail tariffs.

11 See National Party "100 point economic plan" discussion of "Electrify NZ".

12 Improving retail market monitoring: Clause 2.16 information notice | Our consultations | Our projects | Electricity Authority (ea.govt.nz)

3. Connection pricing

3.1. Connection pricing refers to the upfront payments an access seeker makes to connect to a network (or alter an existing connection).

3.2. For connection pricing, we have decided to progress development of a potential Code amendment that would require distributors to set upfront charges at an efficient level, in collaboration with a technical group. We consider this to be the best option for connection pricing because:

(a) guidance alone is unlikely to overcome the financial incentives of distributors to reduce their financing burden

(b) it is likely to drive change more quickly and efficiently than alternative options (continuation or targeted call-in)

(c) the Commerce Act 1986 includes mechanisms that help coordinate Code amendments with the Commission's arrangements for controlling revenue paths.[13]

3.3. Some connection pricing settings may be resulting in inefficiently high upfront charges that could act as a barrier to electrification. It is important to ensure upfront charges are set at an efficient level. This will help access seekers and distributors optimise their investments, resulting in better network utilisation and lower costs to consumers.

3.4. While not justifying regulation, establishing rules for connection pricing would align New Zealand with comparable jurisdictions, which have a less light-handed approach to ensuring efficient network access arrangements. This has advantages as there is existing information and experience to apply to potential methods in New Zealand. Assuming some form of control is our preferred option, we aim to consult on a draft Code amendment, likely in October 2024.

3.5. We will collaborate with a technical group on this work. This is an opportunity for stakeholders with appropriate expertise to be involved in developing the settings for a potential Code amendment on connection pricing. The group will help us ensure options are workable and practical in the local setting.

Context for connection pricing

3.6. Upfront payments for connections may include:

(a) fees, which contribute to administrative costs

(b) capital contributions, which are an upfront payment toward the cost of:

(i) dedicated assets (for access seeker use) owned by the distributor

(ii) necessary modifications or upgrades of shared assets (that serve other customers as well as the access seeker)

[13] The Commission sets revenue paths for non-exempt distributors. For a list of exempt distributors, see the Commerce Commission's webpage Consumer owned electricity distribution businesses at: https://comcom.govt.nz/regulated-industries/electricity-lines/our-role-in-electricity-lines/consumer-owned-electricity-distribution-businesses

(iii) system growth investment more generally (that is, any investment that's primary driver is to add capacity)

(c) vested assets, the construction and funding of assets by a party who then transfers ownership of the asset to a distributor.[14]

3.7. Connection charges are becoming more important due to the growing volume of activity from access seekers driven by the electrification of transport and process heat and urban housing development.

3.8. This context presents new challenges for distributors who face a step change in connection requests, a changing profile of access seekers and pressure on regulatory allowances.[15]

3.9. Many distributors are also anticipating a growing need to invest in upgrading network capacity – that is, system growth investment. This can be driven by connection demand and by growth in peak demand from existing connections (for example, as households electrify their heating and transport). This means there is growing scope for distributors to optimise their system growth investment – for example, through proactive investment ahead of demand or through use of non-traditional solutions, such as flexibility procurement.

3.10. Connection pricing arrangements are important because they affect:

(a) allocation of costs between access seekers and existing network users

(b) incentives for access seekers to ensure connection costs are efficient, for example, in terms of the location and capacity of their connections

(c) incentives for distributors to ensure connection costs and their wider growth programmes are efficient

(d) transaction costs for access seekers and distributors

(e) coordination incentives.[16]

Current situation

3.11. Distributors recover their costs in two ways:

(a) upfront (connection pricing) – fees, capital contributions and vested assets

(b) ongoing (network pricing) – use of system charges paid by network users; typically billed monthly based on annually-determined rates.

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14 A vested asset is defined in the Commission's *Electricity Distribution Services Input Methodologies: Determination 2012* as "…an asset associated with the supply of electricity distribution services received by an EDB – (a) without provision of consideration; or (b) with provision of nominal consideration" (page 53). See: https://comcom.govt.nz/__data/assets/pdf_file/0017/60542/electricity-distribution-services-input-methodologies-determination-2012-consolidated-as-of-23-april-2024.pdf

15 Including because connection expenditure is directly demand-driven and less predictable than most other classes of investment.

16 For example, if access seekers fully fund capacity expansions triggered by their connection, then they may be disadvantaged relative to parties who connect later. This can deter efficient investment in anticipatory capacity and encourage free riding (that is, access seekers delaying their connection until another party has triggered and paid for necessary upgrades).

3.12. Each cost recovery method has different implications for distributors.

(a) Costs that are not recovered upfront are recovered over the assets' life.[17]

(b) For non-exempt distributors, the Commission controls maximum ongoing revenue.[18]

3.13. Distributors are free to decide how much they wish to recover upfront. However, they must disclose:

(a) their policy – typically described as a 'capital contributions policy'

(b) their methodology for setting annual billing rates

(c) how their pricing aligns with distribution pricing principles[19]

(d) historical and forecast expenditure breakdowns, including the value of capital contributions and vested assets[20].

3.14. In addition to the above:

(a) some distributors must apply regulated terms for distributed generation connection, which include specific pricing principles.[21] These do not prescribe the balance between upfront and ongoing charges, but they do limit how much can be recovered in total

(b) we provide guidance on how to comply with the pricing principles, and we have published pricing 'scorecards' for each distributor.

3.15. In the July 2023 issues paper Targeted reform of distribution pricing, we highlighted that a growing share of connection investment is being funded through capital contributions.[22] We also illustrated the wide variation in distributors' reliance on capital contributions.[23]

3.16. We have analysed this area further, using updated information disclosures, which we present and discuss below.

3.17. Financeability is an issue in the Commission's process for setting revenue paths for non-exempt distributors for the period from 2025.[24] Increasing upfront charges is

17 Distributors must use financing to cover differences in timing between outgoing and incoming cash flows.

18 The control arrangements aim to limit excessive profits while providing incentives to innovate and invest, improve efficiency and keep prices low. The objectives of the Commission's control arrangements are set out in full in s52A of the Commerce Act 1986.

19 We publish distribution pricing principles, while the Commission governs disclosure obligation. The principles are included as Appendix A and can be found at: Distribution pricing | Electricity Authority (ea.govt.nz)

20 Vested asset values are only recorded in terms of consideration paid by the distributor, not the full cost of establishing the asset.

21 Distributed generation pricing principles are set out in Schedule 6.4 of Part 6 of the Code. Part 6 (ea.govt.nz)

22 Electricity Authority, *Targeted reform of distribution pricing: Issues paper*, Figure 5, page 45.

23 Electricity Authority, *Targeted reform of distribution pricing: Issues paper*, Figure 6 page 46.

24 Oxera, on behalf of the 'big six' distributors (Aurora, Orion, Powerco, Unison, Vector and Wellington Electricity), argue the complementary concept of 'investability' should also be considered by the Commission when it determines revenue paths. Report found at https://comcom.govt.nz/__data/assets/pdf_file/0027/347517/Big-6-EDBs-financeability-issues-paper-submission-15-March-2024.pdf

one ‘lever’ distributors can currently use to reduce their financing burden, so connection pricing and financeability are inter-linked issues.

Problem statement

3.18. Distributors do not have strong or consistent incentives to ensure connection pricing is efficient. They may be driven to use high upfront funding to reduce:

(a) the scale of their financing task (Upfront charges shift the financing burden for new assets from distributors to access seekers.)

(b) cost recovery risks (Revenue control arrangements partially protect distributors against non-recovery of investment in stranded assets should a customer exit prematurely, whereas upfront funding can provide full protection.)

(c) initial price impacts for existing customers (High upfront charges mean lower target revenue, recovered through ongoing charges. Where high upfront charges do not dampen connection growth, this would translate to lower use of system prices, that is, lower target revenue per connection.).

3.19. High upfront charges may be inefficient if they:

(a) deter efficient connection growth (Connection growth benefits consumers provided new connections generate at least enough revenue over their lifetime to cover their avoidable costs. If upfront charges are significantly higher than needed to meet this condition , they risk deterring connection growth to the detriment of all consumers.)

(b) weaken distributor incentives for efficient cost control (Investment funded through upfront charges operates outside the efficiency incentives provided by revenue control arrangements.)

(c) deter efficient investment options (Access seekers have weak incentives to fund investments that optimise overall network costs rather than minimising their own upfront charges.[25] Reliance on capital contributions can also encourage distributors to adopt an inefficiently reactive and piecemeal approach to network development and favour CapEx solutions.[26]).

3.20. Our focus is on determining whether an intervention to prevent high reliance on upfront charges could deliver a net improvement in connection pricing efficiency.

[25] This is particularly acute where a ‘first mover’ bears a high share of the cost of building capacity that stands to benefit multiple parties – including existing users and future access seekers.

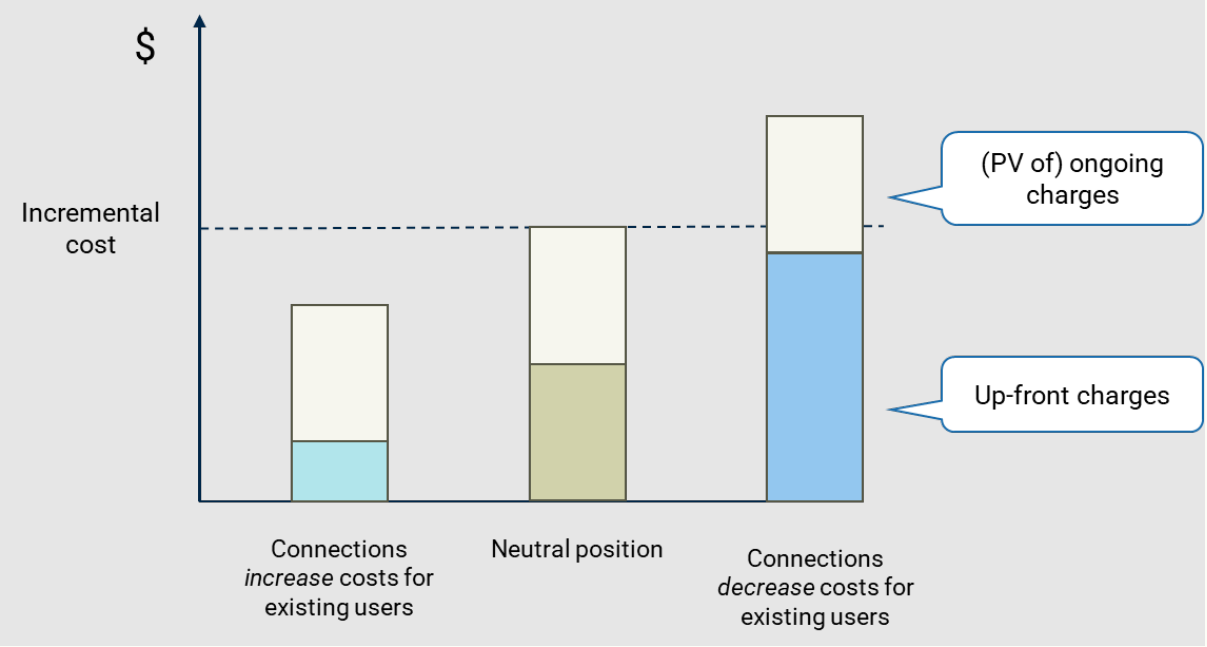
[26] It is sometimes more efficient to invest in network development ahead of demand, which is difficult to fund from a revenue source that is sporadic and tied to connection activity. In other cases, it can be efficient to adopt OpEx solutions (such as procuring flexibility) instead of building new capacity. Capital contributions can also be a poor funding source for such approaches.

What is the efficient level for upfront charges?

When an access seeker connects to a network, they contribute incremental revenue in the form of upfront and ongoing payments (together known as 'access charges'). Their connection will also add costs to the network (known as 'incremental cost').

If access charges precisely equal the incremental cost, then this is a neutral position, with existing users no better or worse off when a new user connects.[27] This neutral position is at the very lower end of the relevant subsidy-free range.[28]

Connection pricing considerations



At the neutral position, upfront charges are set well below incremental cost. To calculate a neutral upfront charge, a distributor would:

- calculate (the present value of) the incremental cost
- deduct (the present value of) ongoing revenue.

Incremental cost typically has two potentially material components.[29] These are:

- extension assets
- capacity upgrades.

For most connections, the neutral upfront charge would be less than 100% of the cost of the extension assets – the access seeker only pays enough up front to ensure they have no net impact on other users over the life of their connection.

27 Over the life of the connection, there may be years where existing customers are better or worse off, but over the lifetime of the new connection, the impact is neutral.

28 The relevant subsidy-free range in this case is bounded by the incremental and bypass costs of the connecting customer. This is different from the subsidy-free range for target revenue allocation between consumer groups.

29 Other components, such as incremental operating costs, are typically small.

If access seekers are major contributors to capacity upgrade pressures, then the capacity upgrade component of incremental costs could be material. When assessing this component, distributors should be careful to ensure they do not over-allocate upgrade costs to access seekers, recognising that upgrades typically:

- accommodate both connection growth and organic growth, benefiting existing and future network users and access seekers
- replace older assets with newer assets, pushing out the timing of renewal investment.[30]

If upfront charges are set above the neutral point, then access seekers make a net contribution that reduces charges for existing users (that is, reduces target revenue per user). This can be seen as a desirable outcome, however, its efficiency depends on the relative price sensitivity (elasticity) of connection and usage demands.

If upfront charges are set above the neutral point, this is likely to dampen some types of connection demand. Traditional sources of connection demand, such as new dwellings, may be relatively insensitive to upfront charges. In contrast, electrification demand is likely to be relatively sensitive, for example, a user may choose not to upgrade their connection to electrify process heat or their vehicle depot.

As distributors reform the structure of their ongoing connection charges to become more cost reflective, usage should become relatively insensitive to connection pricing settings. This is because any reduction in target revenue per customer should flow through to fixed charges.[31] This means key usage decisions, such as whether a household switches from gas to electric heating, should not be influenced by connection pricing settings.

Given these relative elasticities (higher for connection demand and lower for usage demand) the most efficient upfront charges will be toward (or at) the neutral position. This ensures pricing is subsidy free, cost reflective and the least distortionary.

3.21. There are other aspects of connection pricing efficiency incentives that are relevant to our wider work programme. Distributors may inefficiently transfer risk to access seekers by:

(a) declining to tailor services to access seeker preferences, for example, by refusing to provide a flexible or non-secure connection option

(b) overly constraining contestability, for example, by allowing only locally approved electrical contractors to carry out works

(c) under-providing cost certainty, for example, by costing projects individually and passing on actual costs.[32]

30 Upgrades may also deliver other benefits, such as, greater operating flexibility and reduced losses.

31 Or other charges designed specifically to avoid influencing use.

32 It can be efficient for distributors to bear some project risk and to provide standardised rates for some connection work. This can enhance efficiency where the approach allocates risk to the party best placed to manage it. Standardised prices can also reduce transaction costs for suppliers and access seekers. However, standardised rates may not be compatible with enhanced contestability (due to 'cherry-picking', whereby competing network builders target connections with lower-than-average costs, which drives up the standardised prices over time).

3.22. Finally, the diversity of approaches to connection pricing across New Zealand contributes to transaction costs for access seekers if they or their advisers and suppliers are operating across networks.

3.23. Currently, we plan to:

(a) consider risk allocation issues where they are relevant to option designs that require upfront charges be set at an efficient level

(b) consider these issues through our work on non-price barriers (for example, our work to improve connection processes)

(c) treat changes in transaction costs as a potential factor when considering overall costs and benefits.

Options from the July 2023 issues paper and proposed by submitters

3.24. The options we proposed in July were:[33]

(a) do nothing

(b) extend practice note and scorecards to address connection pricing methodologies

(c) prohibit or mandate specific approaches, for example:

(i) prohibit pricing methodologies that allow overly deep contributions, contributions to anticipatory capacity and overly high contributions to general system growth

(ii) set caps on fees or on cumulative fees (where an access seeker has to apply multiple times to find a suitable site)

(iii) mandate particular approaches for some connection types or classes of access seeker. For example, we could require standardised charges or standardised cost building blocks for public electric vehicle (EV) chargers and housing

(d) call in connection pricing policies for review and approval, either for specific distributors or across the board. For example, we could call in:

(i) methodologies of high-risk distributors who have heavy reliance on contributions and high activity levels or high levels of access seeker dissatisfaction

(ii) treatment of cumulative fees for repeat applications.

3.25. We asked submitters if there were other options we should consider for connection pricing.[34] Submitters suggested a range of options, including, working collaboratively with electricity distribution businesses (EDBs), undertaking a joint project with the Commission, increasing our knowledge and understanding of the area and considering the wider implications of any changes to connection pricing.

[33] Electricity Authority, *Targeted reform of distribution pricing: Issues paper*, page 49.

[34] Ibid, page 50.

Submissions received and our assessment of the submissions

3.26. We received significant feedback on connection pricing. From a total of 52 submissions and cross-submissions, 32 engaged directly with the connection pricing issue. Connection pricing was a contentious consultation topic.

3.27. Four main themes emerged from the submissions.

(a) Distributors generally disputed the case for intervention.

(b) Access seekers highlighted challenges in the current environment and argued for urgency.

(c) Submitters commented on aspects of connection pricing theory.

(d) Distributors highlighted links between connection pricing and revenue paths.

3.28. Below we provide example submissions on each of the above themes, followed by our responses to the submission points.

Distributors dispute the case for intervention

3.29. A common argument was that intervention should not be contemplated until after distributors have had an opportunity to understand and respond to our expectations – that is, regulation should be seen as a fallback (or sanction) if voluntary methods fail. For example:

> ‘Given the Authority has been largely silent on what efficient connection pricing looks like, the Authority should not be critical of EDBs’ approaches developed in the absence of any advice to the contrary.
>
> Therefore, the only acceptable option is for the Authority to provide unambiguous guidance to EDBs on its expectations for connection pricing and allow EDBs sufficient time to respond and incorporate this guidance into their connection policies and prices.’ – **ENA**
>
> ‘The issues raised regarding connection processes and connection charges are relatively new (raised within the past 12 months and not yet incorporated into pricing methodology updates).
>
> As an alternative to the options provided in the paper, we prefer the Electricity Authority to take a collaborative approach to work with EDBs to develop practical industry guidance regarding the connection process and new connection charges.’ – **Orion**

3.30. **Our response:** We do not agree with the premise that control options should only be contemplated after providing an opportunity for voluntary compliance. Rather, we should select the option that best promotes our statutory objective. This could involve moving straight to control if, for example, we judged that voluntary measures would not be effective and the risks associated with control were manageable.

3.31. Some submitters argued that targeted intervention would be preferable to broad control options. For example:

> ‘Further investigation of perceived outliers in EDB pricing approaches to understand reasoning would be an appropriate first step for the Authority to take. Targeted intervention could be considered if issues are found however a

feedback, education and discussion approach would still be strongly preferred in the first instance.' – **PowerNet**

3.32. **Our response:** We note that even though control might be broadly applicable to all distributors, its impact could be targeted. For example, setting an upper limit on capital contributions only impacts funding for distributors whose contributions are above the limit.

3.33. Some submitters argued that a stronger evidence base was needed before intervention could be contemplated, including because change can be destabilising. For example:

> 'It would be inequitable …for consumers if significant changes to capital contribution policies are mandated based on perceptions that the Regulator has instead of hard evidence of any issue or "wrongdoing" by EDBs.' – **Network Waitaki**

3.34. **Our response:** There is a strong case for proceeding to develop a draft Code amendment for consultation. We consider that it is unlikely that a voluntary approach relying on guidance alone would be sufficient for connection pricing as distributors have strong financial incentives to manage their financing burden by raising upfront charges. We will continue to examine evidence as part of this process, and consultation will provide further opportunities for stakeholders to provide evidence for us to consider before we decide whether to make an amendment – we will consider all the available evidence before making a decision.

3.35. Submitters also highlighted the complexity of connection pricing, and the risks of regulatory intervention. For example:

> '… we are very concerned that the Authority's intent to intervene in [connection pricing] may have adverse and unintended consequences, particularly for smaller consumers. They will end up paying higher prices for capacity upgrades driven by new load customers. We caution against any change, and instead urge the Authority to take time to work with the industry. A better understanding of the problem is needed, the rationale for difference approaches, and a focus on working through with the ENA on standardising terminology, processes, and approaches.' – **Northpower** and **Top Energy**

> 'Capital contributions are but one parameter in a whole set of parameters used in determining pricing strategy and pricing levels – a significant change in the application of one parameter has a flow-on effect on all the variables that are used to achieve the company's objectives as set out in its Statement of Corporate Intent. These flow-on effects could have significant impacts on customers and introduce fairness and equity issues.' – **Network Waitaki**

> 'Waipā Networks notes that this is the first time the Authority has indicated it wishes to address connection policies and as such its views are very high level and lacking analysis of the flow-on effects for some of the changes it is proposing. It would therefore be inappropriate to prohibit or mandate certain approaches, and as such Waipā Networks prefers 7.30 (b), extend practice note and scorecards to address connection pricing methodologies, following further detailed consultation with Distributors.' – **Waipā Networks**

3.36. **Our response:** We acknowledge that connection pricing is complex. To mitigate risks, we are working closely with the Commission, will form a technical group and will consult on the Code amendment to ensure our decision making is well informed.

3.37. Finally, submitters pointed to the small number of connection-related complaints:

> 'EDBs do the heavy lifting on annually connecting tens of thousands of consumers. This involves managing a variety of third parties, complex and varied sites to work on (greenfields and brownfields each having their own complications), and high consumer/developer expectations. For Vector, new connections are generally between 12,000 to 14,000 connections per year across the greater Auckland area. This is done with nearly no complaints from connecting parties as can be seen by the small number of Utility Disputes Limited (UDL) complaints, all while the number of connections faced by EDBs is growing rapidly.' – **Vector**

3.38. **Our response:** We note the information provided on complaint volumes but do not think this necessarily provides evidence that current connection pricing settings are efficient, especially as some distributors are part way through rebalancing funding towards greater reliance on upfront charges.

Access seekers argue for urgency

3.39. In contrast to the distributors, access seekers argued for urgent reform of network access arrangements (including connection pricing). For example:

> 'My experience in working with distributors to negotiate connection arrangements for generators and load customers suggests that both the Control and Call-in approaches will be required to give access seekers meaningful access to distribution pricing that supports an economic transition to a low emissions future.
>
> … I agree with the Authority's approach to pricing reform and believe development of regulated default connection terms and pricing principles will benefit the entire industry as many distributors are not large and have limited resources to develop their own standards.
>
> … Time is also of the essence. Access to network capacity is one of many inputs to decarbonisation projects that need to be managed.' – **Stephen Peterson**
>
> 'Private sector investment into public charging networks is starting to be seriously hampered because of the costs (connection and use of system charges) and processes associated with electricity network issues. Demand for energy by EVs is growing quickly, and if we do not enable investment in public charging infrastructure, there will be undesirable consequences for EV users, electricity networks, and for New Zealand's electrification opportunities and decarbonisation targets.
>
> The weight of evidence that is presented in this submission has us convinced that the Authority needs to be more definitive about network access pricing and other connection arrangements … the evidence base that we set out below suggests to us that the Authority has underestimated the scale and scope of the current issues. The constraints that we face are "live" and urgent, and we need a remedy that is structured and enduring.' – **Drive Electric**

‘Access seekers are facing connection problems beyond electricity across gas, 3-waters, roading and telecommunications networks. The nature of the problem is very similar across the networks but is complicated by lack of consistent government policy and regulation across the networks.

The consequence of connection problems is that the cost of new housing is higher than it should be. A new house will cost up to $50,000 more than it should if there are multi-network connection problems. This is a material cost to new home buyers.’ – **Andrew Body**

‘The current approaches to connection charges prejudice and disincentivise new domestic and small business connections. High connection charges are a significant barrier for consumers who wish to connect to the electricity grid.’ – **Consumer Advocacy Council**

3.40. **Our response:** We acknowledge the call for urgency across connection pricing and wider network access arrangements. We have parallel workstreams underway on these matters and are seeking to make rapid progress while being careful to ensure we take the necessary time to understand these complex issues and follow a robust process that tests options and enables stakeholder input.

Submitters commented on connection pricing theory and practice

3.41. Many submitters highlighted the importance of avoiding inefficient (or unfair) subsidies. For example:

‘An EDB that is not recovering the full costs of connection from the connecting party (including the cost of bringing forward system growth investment) will need to invest in the network to support the connection. This approach could be viewed as subsidising the cost of connection for connecting parties.

Any subsidy for connection costs will incentivise more connections but ultimately harm consumers who are paying for the connection costs.’ – **Horizon Energy Group (HEG)**

‘PowerNet supports equitable pricing but is concerned at any implication that any category of connection should be cross subsidised by others, that is, inequitable sharing of subsidy free ranges. PowerNet suggest that any subsidisation to accelerate electrification should come via explicitly targeted government agency funding and notes that customers may already access such funding.’ – **PowerNet**

‘Firstlight Network is very wary of the possible equity issue that would result from subsidising new connections and upgrades.’ – **Firstgas Group**

3.42. **Our response:** We agree that connection pricing should be subsidy free so new connections do not make existing users worse off. This involves ensuring incremental revenue (upfront and ongoing) from new connections covers at least the incremental cost of new connections. This does not imply that upfront payments must cover the full cost of network extensions.

3.43. Submitters also highlighted the virtues of maintaining stable pricing settings over time. For example:

‘… intervention into a practice that has been in place for decades has the potential to disrupt the balance of capital contributions, connection levies, lines

charges and create an uncertain environment for investors in our region – if rules can be changed overnight after decades of stability.' – **Network Waitaki**

'Any change in approach to connection pricing requires EDBs to be extremely mindful of intergenerational equity issues. For existing customers who have paid up front for their connections, a change in approach risks new consumers benefiting from the contributions of existing consumers without making a contribution of their own.' – **ENA**

3.44. **Our response:** We note that stability of pricing is a relevant consideration, particularly when change risks undermining investment confidence. We observe that many distributors have maintained stable settings over time, however, others have not and are increasing their reliance on upfront payments.

Distributors highlighted the link between connection pricing and revenue paths

3.45. Distributors agreed there is an important link between connection pricing settings and revenue paths. For example:

'We also note the direct and significant impact reducing capital contributions would have on CapEx forecasts in EDBs' Asset Management Plans (AMPs) with subsequent flow-on effects for expenditure allowance setting for the Commission resetting of EDB price paths from 1 April 2025. The Authority needs to carefully consider that the Commission makes its final reset decision in November 2024 and the wide-ranging jurisdictional implications of interfering with the process. Therefore, any mandated changes to capital contributions by the Authority would need to occur before the Commission's reset draft decision in May 2024. The Authority should not (and would be acting in error) be so bold as to assume reopener mechanisms in the Commission's regime for so many EDBs can simply alleviate this issue. It is unlikely that reopeners could respond in time to meet the requirements of most access seekers and significant uncertainty would remain over the outcome of any reopener process.' – **Vector**

'The Electricity Authority will need to consider the implications of any changes that impact EDBs CapEx or OpEx allowances and the mix between these (especially around connection charges) given the limited ability to reopen a 5-year price path.' – **Orion**

3.46. **Our response:** We are aware of the links between capital contribution policies and revenue path determinations. This is relevant to problem definition, option selection and implementation considerations. We are working with the Commission to ensure proper consideration of these links.

Submitters had mixed views on other issues

3.47. In addition to the key themes above, submitters commented on a range of connection pricing matters.

3.48. There was broad support for greater standardisation around matters such as terminology and processes. For example:

'While each EDB will have unique approaches to the funding of capital contributions, we think there are opportunities to standardise language and terminology across EDBs capital contributions policies to improve understanding for consumers.' – **Aurora Energy**

‘Waipā Networks agrees with 7.27 with regards to greater consistency between Distributors with regards to terminology, processes and approaches but notes that considerable work is already underway in this area through the likes of ENA and the Northern Energy Group.’ – **Waipā Networks**

3.49. There were conflicting views on contestability. For example:

‘I suggest the Authority considers why wouldn’t we create a national pool of certified contractors rather than a series of local pools? This would support a common standard of competence and support creating scale, innovation and competition in network deliver and maintenance capacity.’ – **Stephen Peterson**

‘Allowing contract workers to connect would create significant long-term issues for distributors because distributors need to maintain the assets for their 50-to-60-year life and non-standard or poor construction will increase equipment faults leading to long-term increased outages and high costs for the customers. For these reasons Counties Energy ensures the reliability and quality of the network by limiting 3rd party contractors undertaking vital work on the network.’ – **Counties Energy**

3.50. There were comments about risk allocation, for example:

‘I have seen a connection budget reduced 90% through collaboration with the distributor’s engineers …

Despite the collaborative effort … the distributor was not prepared to contract for capacity above the n-1 substation constraint … It is worth noting that the distributor faces limited incentives and perceived risks of providing network capacity above the standard n-1 operating range’ – **Stephen Peterson**

‘The capital contribution arrangements I have seen have always provided that the risk of cost variances are payable by the access seeker with no incentive for distributors to ensure these costs are efficient.’ – **Stephen Peterson**

3.51. **Our response:** We will continue to consider these comments. Some are relevant to our work on non-price access arrangements as part of our regulatory settings work programme, and we will consider them in that context.[35] Our work on Code development and amendments to improve connection processes for large capacity load and distributed generation complements our work on connection pricing (both workstreams address barriers to users wanting to connect to the network).

Updated evidence

3.52. Regulatory allowances and regulatory asset bases for distributors are net of capital contributions. However, the Commission’s information disclosure regime requires disclosure of capital contribution polices and reporting of capital contribution amounts.

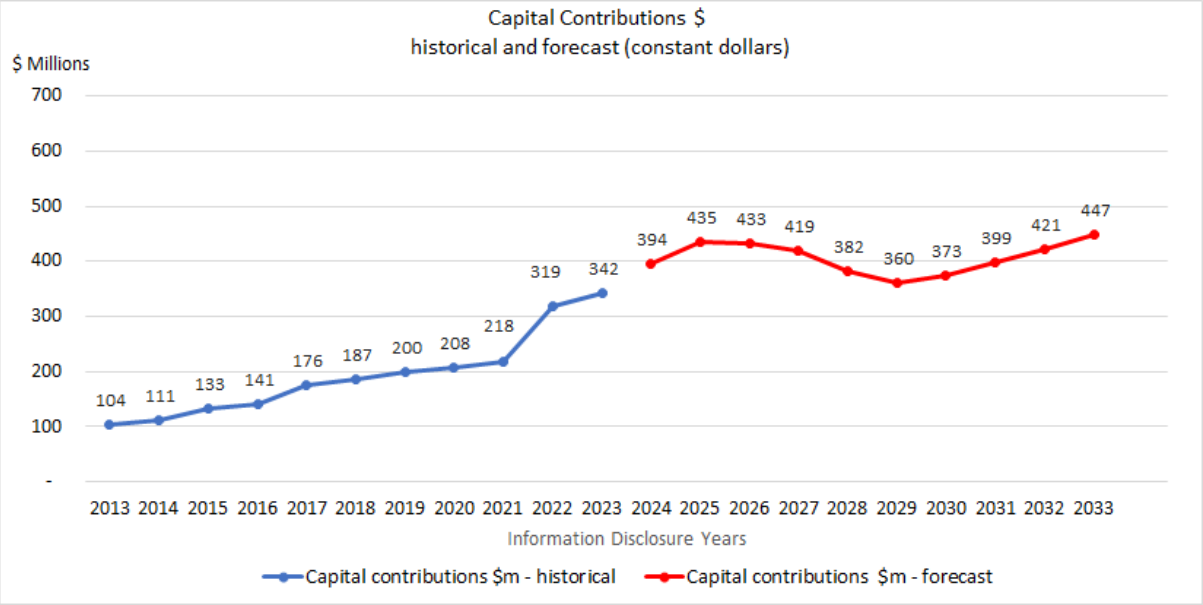
3.53. Distributors must also disclose the value of vested assets, but only the cost to the distributor of acquiring those assets. As such, underlying capital expenditure on vested assets is not captured in regulatory disclosures. Accordingly, we have focused on capital contributions, noting this understates access seekers’ total upfront costs.

35 Updating regulatory settings for distribution networks | Our projects | Electricity Authority (ea.govt.nz)

3.54. In absolute terms, the value of capital contributions has trended up sharply in recent years and is forecast (by distributors) to continue to climb. Figure 1 uses data disclosed by distributors at the end of 2023, adjusted to 2023 dollar terms.

Figure 1: Capital contributions by value, 2013–2033 (constant 2023 dollars)

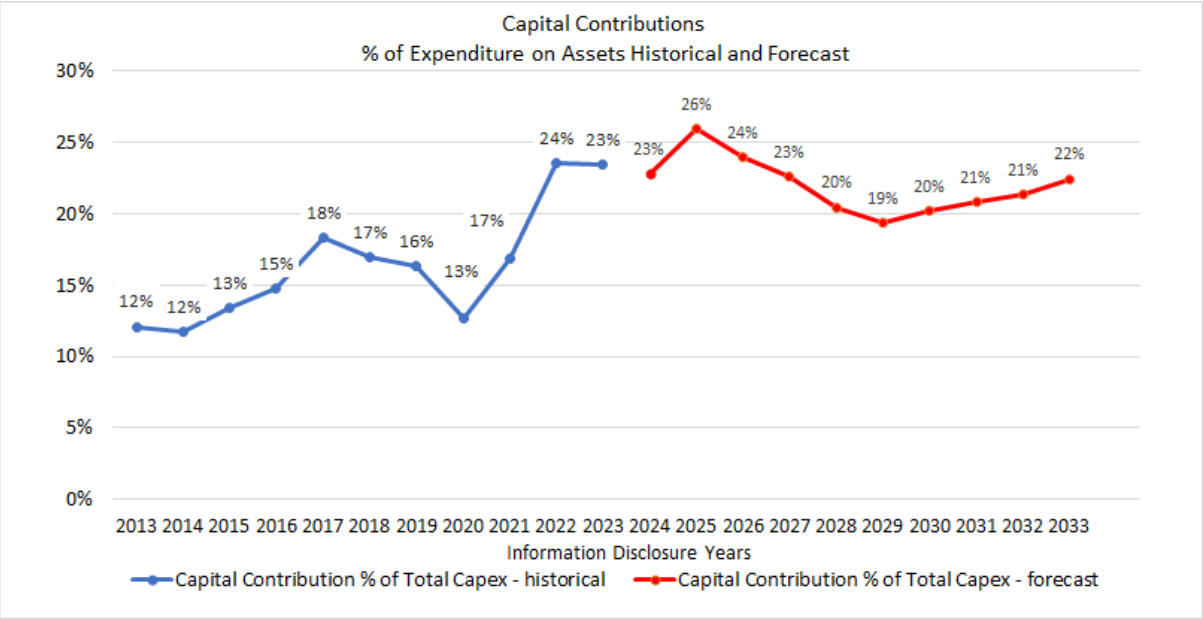
The value of capital contributions has increased recently, and is projected to increase further



3.55. Capital contributions show a similar trend as a percentage of total capital expenditure (albeit with some ups and downs in the forecast), indicating there is a shift in funding sources rather than simply a growth in overall capital expenditure.

Figure 2: Capital contributions as a proportion of expenditure on assets, 2013–2033

Upfront payments have grown as a share of total expenditure and are forecast to remain around this level[36]



3.56. A similar trend is apparent if we consider capital contributions, by category, as a share of the growth expenditure categories of:

(a) connection expenditure – network extensions plus related upgrades and modifications

(b) system growth expenditure – adding capacity to the network to accommodate changes in peak demand or injection.

3.57. There is a clear upward trend in upfront funding (capital contributions) as a portion of connection expenditure. This has steadily increased and is projected to remain at a level where approximately 70% of connection expenditure is funded through capital contributions.

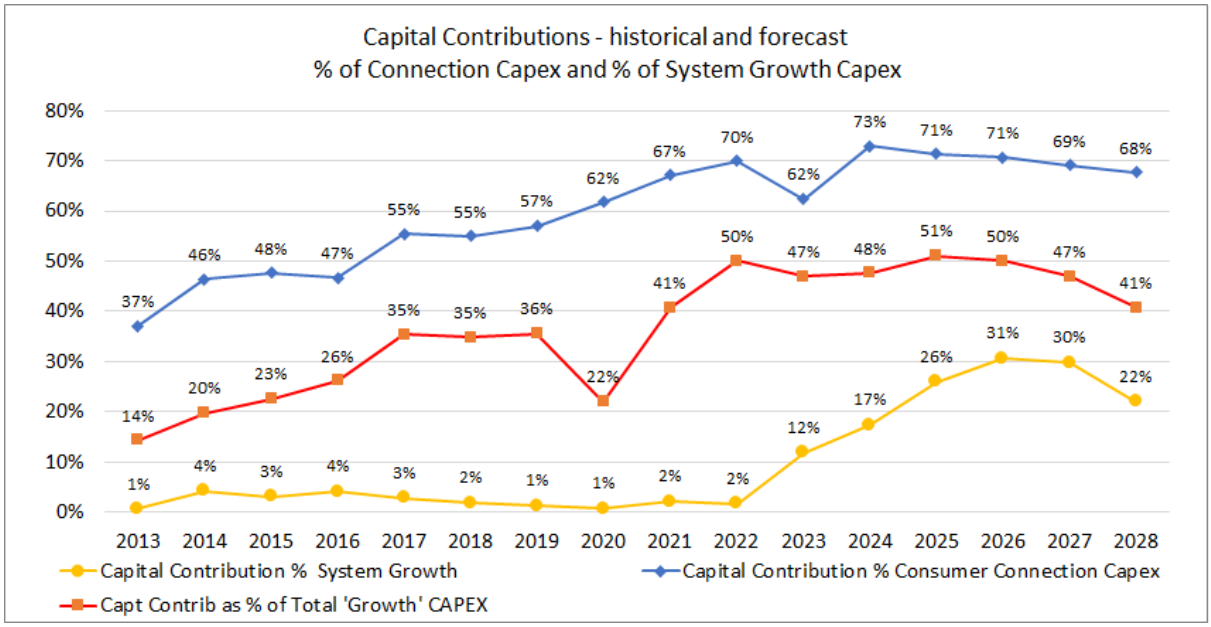
3.58. Capital contributions as a proportion of system growth expenditure increased markedly in 2023 to 12% and are projected to continue to increase to around 30% by 2026, (noting some apparent declines appear in some of the later years' forecasts).

3.59. Figure 3 below also shows the two categories of capital contributions and CapEx associated with growth. The result is a blend of the result for system growth and consumer connection with around half the 'growth' CapEx funded through capital contributions.

36 Expenditure figures for 2020 are impacted by a one-off accounting reversal by Vector following a Commerce Commission investigation. See the Commerce Commission's webpage Commission prompts Vector to reverse moves that would have cost electricity consumers millions

Figure 3: Capital contributions by category % of capital expenditure, by category, 2013–2028

Capital contribution by category has grown as a respective share of CapEx by category



3.60. Finally, there is significant variation among distributors with respect to the degree of reliance on upfront funding. The trends observed above are heavily influenced by a small number of distributors with high capital contributions. Most other EDBs have low capital contributions. The trends observed above represent the aggregate of these two groups.

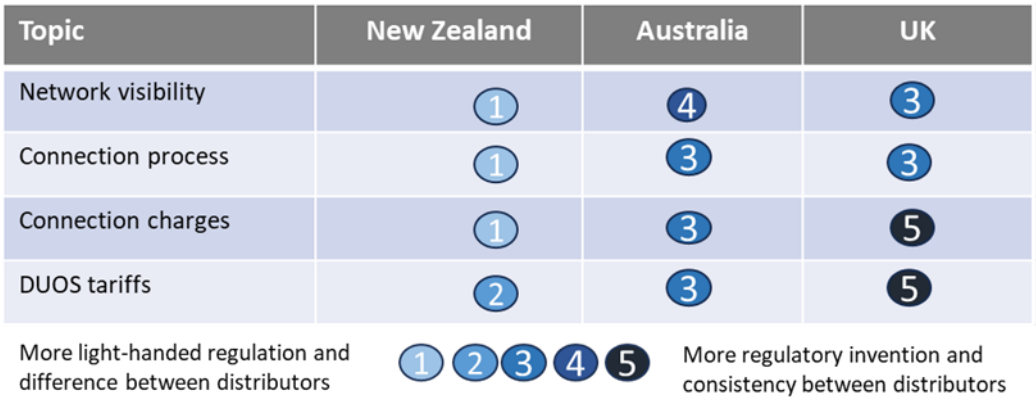
Existing regulation is light handed

3.61. A 2023 report to assess the transition towards EVs and supporting public charging infrastructure compared levels of regulatory intervention and consistency between distributors across New Zealand, Australia and the United Kingdom. The report found the New Zealand approach to be light-handed in comparison.

> 'Higher levels of regulatory intervention and distributor consistency apply in AU and the UK, compared to the light-handed NZ approach leading to significantly more industry differences and less regulatory oversight[37]

[37] Baringa, *Challenges and regulatory policy solutions integrating public EV charging stations: International case studies* (October 2023), page 5,

Figure 4: Comparison of New Zealand, Australia and the United Kingdom electricity distributors, 2023



Note: DUOS = distribution use of system charges.

3.62. For European jurisdictions, the European Union Agency for the Cooperation of Energy Regulators (ACER) published a report comparing electricity network pricing arrangements across 28 European Union jurisdictions. The following are key points from the ACER report.

(a) Pre-determined connection charges (as opposed to charges based on actual cost) are more common for distribution (compared with transmission). The most common dimensions used to set pre-determined charges are voltage level, connected capacity and distance.

(b) Countries that use deep connection charges can encounter first-mover disadvantage issues. Some countries use refunds or cost-sharing methods to address this challenge.

(c) ACER recommended that 'where deep connection charges apply and the connection of a network user serves future network users, it should be considered whether cost-sharing is necessary to ensure a fair and non-discriminatory treatment of the network users, also taking into account the administrative cost for the …[distributor]'[38].

(d) ACER also recommended that 'within the next four years, [regulators] should evaluate the advantages and disadvantages of enabling interruptible or flexible connection agreements, having due regard to the countries that already worked on this topic'[39].

Evaluation framework and application to high-level options

3.63. We developed a set of evaluation criteria to help in comparing the high-level options of continuation, call-in and control and to compare specific control options against the counterfactual of the continuation option. In both cases, our aim is to use the

[38] ACER. Report on Electricity Transmission and Distribution Tariff Methodologies in Europe (January 2023), page 50, at https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_electricity_network_tariff_report.pdf

[39] Ibid, page 7

evaluation criteria to help identify the option that best promotes our main statutory objective and communicate more effectively why we have reached that view.

Figure 5: The Authority's evaluation criteria

3.64. Appendix B: Screening high-level options for connection pricing explains our application of these criteria to the high-level options of continuation, call-in and control. Our conclusion is that the control option has merit, is currently our preferred option and warrants further development for comparison against the continuation option. Key factors supporting that conclusion include the following.

(a) Continuation is most effective for changes that distributors are willing to make and least effective where material cost or financial consequences deter voluntary alignment – as may be the case for connection pricing.

(b) We could not apply call-in to connection pricing until a call-in framework was fully designed and implemented. Once developed, we anticipate it would be a relatively resource-intensive and slow option.

(c) The control option clearly fits with our processes for making and enforcing Code and with the reconsideration mechanism for the Commission's determinations.[40]

3.65. In addition, as noted above, New Zealand appears to be an outlier relative to comparative jurisdictions in terms of the amount of regulatory oversight of distributor pricing.

Types of control

3.66. Over the coming months, we will develop and evaluate options for setting upper limits on upfront charges. Options may vary in terms of:

(a) degree – the overall share of connection-related costs that can be recovered through upfront charges

(b) design – how limits are specified, including their form (for example, formulae, methodologies and values) and level of prescription.

3.67. As a starting point, we will consider international approaches that provide ready-made 'templates' for control options. These include:

(a) the Australian Energy Regulator's (AER's) connection charge guidelines[41]

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40 Refer Section 54V(5) of the Commerce Act 1986 requires the Commission, if asked by the Authority to do so, to reconsider a section 52P determination and, to the extent that the Commission considers it necessary or desirable to do so, amend the determination, to take account of any matter referred to in subsection (3) or (4).

41 AER, Connection charge guidelines for electricity customers, April 2023,

(b) the United Kingdom's Office of Gas and Electricity Markets' (Ofgem's) "shallow" and "shallow-ish" approaches.[42]

3.68. These templates differ in degree and design, which has implications for:

(a) overall impact on suppliers and existing customers, in terms of overall reduction in capital contributions and impact on use of system charges

(b) impact on different types of access seekers, including in terms of level and predictability of upfront costs

(c) incentives on suppliers and access seekers, including to optimise solutions and ensure efficient delivery

(d) implementation and operational complexity, including in terms of parameters to be determined upfront and scope for pricing disputes.

3.69. The templates provide a starting point, rather than a rigid menu, and we expect to build on them and consider other approaches in search for the solution that will work best for New Zealand. We are convening a technical group to assist with option refinement.

Interaction with revenue control arrangements

3.70. In November 2024, the Commission will set revenue allowances for 16 non-exempt EDBs for four or five years from 1 April 2025. The allowances will be based on expenditure forecasts that are sensitive to each distributor's connection pricing settings.

3.71. The Commission gathered updated expenditure forecasts from distributors in early 2024 as input towards a draft decision due in May and will make its final decision in November 2024. It is likely both decisions will reflect each distributor's current plans for connection pricing.

3.72. If we decide to alter connection pricing settings, we anticipate this would occur after the Commission's final decision. A decision to limit capital contributions in some way could prompt updates to expenditure plans for some distributors, potentially including to:

(a) reduce the amount netted off forecast connection-driven investment

(b) alter forecast connection volumes

(c) alter forecast system growth expenditure, for example, to reflect altered connection volumes and altered incentives to plan and optimise investment programmes.

42 Ofgem, Distribution connection boundary – discussion note,

3.73. Any distributors materially impacted by these factors have three key mechanisms for addressing revenue path implications. These are:

(a) legislative provisions enabling coordination between Code amendments and Commission determinations[43]

(b) for some less direct impacts, reopener provisions in the input methodologies, including for new programmes of work and for OpEx solutions to system growth

(c) customised price-quality paths (CPPs), which enable a more tailored approach than default price-quality paths.

3.74. We have been working closely with the Commission, and will continue to do so, to ensure workability and to coordinate any changes to connection pricing settings. This could include arrangements for managing a transition such as:

(a) a delay between amending the Code and new requirements taking effect

(b) provision to extend any such delay for distributors entering a CPP process.

3.75. We are also aware that changes to connection pricing settings could interact with the LCC mechanism. For example, rules restricting connection charges could interact with LCC cost thresholds (which control the availability of the LCC mechanism). We will continue to work with the Commission to ensure any such possible effects are properly considered.

Next steps

3.76. As set out above, our planned next steps include:

(a) convening a technical group to assist with refining the workability of potential connection pricing rules – providing an opportunity for stakeholders to be involved in developing the settings for a potential Code amendment on connection pricing

(b) consulting on a draft Code amendment, likely in October 2024

(c) subject to the outcome of consultation, amending the Code in 2025, with suitable transition arrangements to enable impacted distributors to work with the Commission on any changes to their revenue paths.

3.77. This programme of work includes:

(a) developing and evaluating options (against the counterfactual of continuing current arrangements)

(b) as part of the above, assessing the costs and benefits of intervention (We do not expect this to be a fully quantified assessment given the complexity of interactions between pricing rules and supplier and access seeker behaviour)

(c) developing information that provides context on consumer impact, noting we will not be able to forecast consumer impact given the range of moving parts involved (for example, the links between capital expenditure inputs and revenue path outputs via various smoothing mechanisms).

[43] See section 54V of the Commerce Act 1986.

4. Peak and off-peak pricing

4.1. We consider the best option for the Authority to take now to encourage more efficient peak and off-peak price signals is to refine the distribution pricing practice note and our approach to scorecards. Guidance on the pricing principles and evaluation of the alignment of distributors' pricing practices with the principles has been relatively effective to date (we have seen improvements in distributors' pricing scorecards, with the overall score improving on average from 2.7 in 2020 to 3.9 in 2023).

4.2. We consider there is scope to develop further guidance to sustain momentum. Hence, we are planning to focus on guidance during 2024 and to resume pricing scorecards in 2025. We will review our options beyond 2025, depending on the progress we observe. We will also be progressing recommendations from MDAG, in particular recommendation 4 on cost-reflective pricing.

4.3. As our next step, we will publish an open letter for distributors that confirms our expectations for distributors' pricing and our targeted focus areas.

4.4. We acknowledge that many distributors have made pricing reforms since the issues paper was published. We will be following innovations like Aurora Energy's trial of feed-in prices with interest.[44]

Context

4.5. As discussed in chapter 4 of the July 2023 issues paper, prices during peak demand periods should signal the cost consequences of network usage for networks that anticipate having insufficient network capacity to meet anticipated demand (anticipated congestion). This creates a pay-off for avoiding peak periods (or allowing load management) that users can weigh up against the benefits of peak-time usage. This dynamic is particularly important at a time when electrification is becoming a major driver of network investment.

4.6. As discussed in chapter 5 of the July 2023 issues paper, problems arise when distributors set material usage charges for off-peak periods – even though the cost of network usage at off-peak times is typically near zero. This deters efficient usage, reduces the cost advantage of key electrification technologies and risks over-stimulating off-peak generation.

Current situation

4.7. Although most distributors facing demand growth have introduced Time of Use (TOU) prices, they do not appear to be consistently signalling the cost of capacity expansion or congestion. Where tariffs do send peak price signals, there is little evidence that robust and transparent analysis has been used to link the strength of the signal (or the price differential between controlled and uncontrolled tariffs) to the cost consequences of usage. As a result, pricing is not necessarily sending accurate signals regarding the cost consequences of peak usage, which may result in inefficient investment.

[44] Aurora Energy is planning to use net usage during their control period for tariff setting for medium-sized customers on application. For more information, see Aurora's Pricing methodology (auroraenergy.co.nz)

4.8. That said, we observe that 23 out of 29 distributors currently have some form of TOU pricing (including day/night prices).[45] This represents significant progress over the last five years.

4.9. Material off-peak usage charges remain common, due in part to: compliance with the low fixed charge (LFC) regulations,[46] the continued availability of legacy tariff structures with uniform usage charges (that do not vary by time of day) and some distributors continuing to use an individual customer's anytime maximum demand (AMD) as a charging metric to recover residual costs. This deters efficient use and sends inefficient investment signals for technologies that matter for efficient electrification. We have observed some progress in this area, with the weighted average off-peak price reducing to 2.4c/kWh.[47]

Options proposed in July 2023

4.10. The options proposed for peak pricing were:

(a) do nothing

(b) refine the practice note and extend scorecards

(c) prohibit or mandate specific approaches.

4.11. The options proposed for off-peak pricing were:

(a) do nothing

(b) extend the practice note and score cards to address off-peak price signals

(c) prohibit or mandate specific approaches

(d) call-in off-peak pricing.

Submissions received and our assessment of the submissions

4.12. We received 30 submissions and cross-submissions on peak and off-peak pricing:[48] seven from retailers, 22 from distributors (including the ENA), three from private individuals and one each from Transpower, the Consumer Advocacy Council and the not-for-profit charity Rewiring Aotearoa.

4.13. In general, distributors supported more guidance rather than regulation.[49] The main supporting arguments given for no more regulation were as follows.

(a) Regulation makes it harder to manage the transition path to low emissions and customer price increases.

(b) There could be unintended consequences.

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45 Some of the remaining six distributors may not require TOU tariffs as they are not experiencing demand growth.

46 The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the LFC regulations) are expected to be phased out by 1 April 2027. For more information, see the Ministry of Business, Innovation and Employment webpage Phasing-out the Low Fixed Charge Tariff regulations at: www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-consultations-and-reviews/electricity-price/phasing-out-low-fixed-charge-tariff-regulations/

47 2023 tariffs weighted by installation control point (ICP) numbers.

48 Some distributors submitted together and so were counted as one submission.

49 Submitters that supported this position included, Orion, Wellington Electricity (WE), Counties Energy, PowerNet, Powerco, Firstlight Network, The Lines Company, WEL Networks, Vector, Network Waitaki, ENA, HEG, Waipā Networks and EA Networks.

4.14. We are also concerned about these issues.

4.15. Distributors also requested guidance on long-run marginal cost (LRMC) pricing.[50] We are investigating providing guidance on this topic.

4.16. Non-distributor submitters were mixed on their views about regulation, with some such as the Consumer Advocacy Council supporting a single distribution pricing methodology and Rewiring Aotearoa supporting the control and call-in option, requiring distributors to adopt TOU tariffs (including two-way peak tariffs).

4.17. We do not currently favour intervention with respect to peak and off-peak prices. We agree with those submitters that considered regulation of peak and off-peak charges to be unnecessary at this time. We expect distributors to respond efficiently to our guidance and open letters. Distributors have generally moved in alignment with our guidance and transitioned towards TOU pricing and lower off-peak prices over the last five years, and we are continuing to observe progress, as noted in paragraphs 4.8 and 4.9 above. This is reflected in the scorecards, which have had efficiency scores improve from 2.2 in 2021 to 3.4 in 2023. In the 2023 scorecards process, we assessed distributors' alignment with the five focus areas set out in our open letter on distribution pricing published in September 2022. Distributors averaged a score of 4.4 out of 5 in the focus areas section of the scorecards.

4.18. However, we will keep our position on this question under review. If in future, we see that progress is slowing, then we will reconsider using stronger regulatory measures for peak and off-peak charges.

4.19. A few submitters[51] argued that TOU pricing is too blunt a tool to help with peak signalling and more advanced pricing is required. We acknowledge there are limitations in the signalling utility of predetermined tariffs, however, we believe TOU pricing is a good first step for now (noting that it is reasonably easy to understand and implement). However, we acknowledge the optimal level of pricing granularity will change over time, and we will continue to consider the case for progressively improving the temporal and locational granularity of prices.

4.20. We will also continue to consider the use of complementary measures. For example, we note MDAG's recommendation encouraging us to work with the Commission on regulatory incentives for distributors to accelerate pricing reform and are engaging with the Commission on this topic. Further, we note MDAG's recommendation regarding security-constrained economic dispatch (SCED) at the distribution level and will investigate this recommendation further.

4.21. We note with interest the Rewiring Aotearoa proposal for two-way peak tariffs. This falls within scope of work on incentives for distributed generation investment, and we will be considering this proposal in the near future.[52]

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50 A total of 23 distributors have instituted TOU tariffs of some type. However, not all distributors have linked these TOU tariffs to the cost of capacity expansion. Some distributors are transitioning towards a cost-reflective level of peak/off-peak differential, but not all have identified what this level is.

51 SolarZero, Aurora Energy and EA Networks.

52 We signalled we would research this topic in our decision paper on the Avoided Cost of Transmission (ACOT) Code amendment, and we intend to release an issues paper in mid-2024.

4.22. A number of submitters raised concerns about energy hardship.[53] Some were concerned about an increase in peak charges and/or an increase in fixed charges (enabled by the phase-out of the LFC regulations) impacting low-electricity-use consumers. We are conscious of the hardship concerns raised by submitters and note that:

(a) any price rebalancing will initially make some customers worse off and others better off, with customers that experience energy hardship spanning both groups

(b) it is not clear that such changes will materially impact hardship

(c) a structure with higher fixed charges and lower variable charges can be materially beneficial for consumers in hardship (for example, households with lower incomes and higher energy needs), and lower variable charges reduce the seasonal volatility of bills.

4.23. We consider the transition away from flat tariffs towards greater reliance on fixed charges and TOU pricing will bring significant benefits for consumers, for example, by reducing the incentive to under-heat homes and increasing the benefits of electrification, including EVs and electric heating. It will also encourage off-peak charging of EVs and hot-water cylinders and so defer network investment to the long-term benefit of consumers.

4.24. However, we will continue to consider the potential impact of pricing reform on consumers, particularly as and when we evaluate any potential Code amendments in the future. We intend to carry out more research on ways to measure and mitigate consumer impact, particularly for consumers in financial hardship. We expect to work with distributors on this issue.

4.25. Several distributors expressed a concern that large peak/off-peak differentials could create additional peaks.[54] For example, consumers may set timers for many appliances to begin at 9pm, spiking power use. Distributors have several options to deal with this problem, including extending peak periods to later at night or using shoulder rates. To an extent, this problem could also be addressed through the work on MDAG recommendation 19 – Network capacity in DSF dispatch.[55]

4.26. Some distributors[56] argued that load control has more value than TOU pricing due to its use to manage outages, its certainty of response compared with TOU and its value to the system operator during grid emergencies. We acknowledge that certainty of response is a strength of load control, and we will not be requiring distributors to 'match' the LRMC of their load control discount with their TOU pricing differential. However, we do expect distributors to justify the difference between the two measures.

4.27. Some distributors noted that there was not a great deal of supporting analysis for favouring ICP pricing over grid exit point (GXP) pricing.[57] We note that ICP pricing

53 For example, Northpower and Top Energy, Firstlight Network, 2degrees, Electric Kiwi and Network Waitaki.

54 For example, WE, Firstlight Network, Flick.

55 MDAG, Price discovery in a renewables-based electricity system: Final recommendations paper 2023 (ea.govt.nz), 11 December 2023.

56 For example, Network Waitaki.

57 For example, PowerNet and Network Waitaki.

allows greater granularity and flexibility in assigning customers, however, we are not proposing to require distributors to use ICP pricing at this time.

Next steps

4.28. In 2024, we are planning to focus on providing guidance to distributors on pricing, and in 2025, we plan to resume scorecards. As the next step, we intend to publish a further open letter to distributors on pricing reform in May, clarifying our key focus areas.

5. Retailer response

5.1. We need to work with industry to better understand and progress greater assignment of ICPs to more cost-reflective distribution tariffs. This will include continuing to monitor tariff assignment and engaging with individual distributors to understand what they are doing to help increase assignment. We are still working out how best to support distributors to transition to billing retailers based on metered data on TOU consumption (that is, phasing out the use of profiles and/or data on total monthly consumption for billing). We will seek further information from distributors on this issue during May 2024.

Context

5.2. Most end users pay for network costs through their retail tariff rather than transacting directly with distributors. As such, retailers are the direct consumers of distribution tariffs, so their response to distribution price signals is critical to the effectiveness of our distribution pricing reforms.

5.3. Retailers need to face cost-reflective, time-varying distribution price signals. Such price signals will encourage them to respond more efficiently. For example, they can encourage consumers to shift their consumption to off-peak periods, they can use flexibility resources to directly influence customers' demand, or they can adjust their retail prices.

5.4. As discussed in chapter 8 of the July 2023 issues paper, we are concerned that:

(a) some distributors are still assigning a significant number of ICPs to flat-rate rather than time-varying distribution tariffs, even when those ICPs have suitable smart meters that can accommodate such a tariff

(b) some retailers are failing to submit data on actual consumption, broken down by time of use, for billing ICPs that are assigned to a time-varying distribution tariff – even when those ICPs have a smart meter that records such data.

5.5. These two factors appear to weaken retailer incentives and so significantly contribute to a lack of efficient retailer response to distribution prices – as in both cases, retailers do not face time-varying price signals.

Current situation

5.6. The majority of residential ICPs that are suitable for time-varying tariffs are being assigned to either TOU or day/night tariffs. However, there are some distributors with a significant number of ICPs still assigned to flat-rate/uniform tariffs.

5.7. We are still investigating the extent to which retailers are providing distributors with peak and off-peak consumption data based on usage profiles.

5.8. We are also aware that sometimes retailers are providing distributors with just a single volume data point for total monthly consumption (not disaggregated by time of use) for billing ICPs that are assigned to a time-varying distribution tariff. This is despite those ICPs having a smart meter that records actual consumption by time of use. One distributor estimated that around 14% of the volumes that were submitted during one period in 2023 were aggregated into a single monthly data point, despite having meters capable of recording half-hourly data and that data being available.

Options proposed in July 2023

5.9. The options proposed for the retailer response workstream were:

(a) do nothing

(b) extend the practice note and scorecards

(c) support the transition to billing on actual data

(d) change to control or call-in distribution pricing

(e) monitor retail pricing

(f) change to control or call-in retail pricing.

Submissions received and our assessment of the submissions

5.10. Most submissions agreed with the assignment of ICPs to time-varying tariffs, but several said that exceptions are required for non-smart or non-communicating meters. They also noted that most distributors already have some form of time-varying pricing. ENA encouraged the Authority to support distributors rolling out more stringent assignment policies, and retailers did not raise any objections to stricter assignment of customers to TOU.

5.11. There were several other notable comments made on tariff assignment.

(a) Several submissions asked whether retailers should be required to pass on thorough time-varying distribution price signals to end consumers.

Our response: The Authority's view is that to achieve efficient outcomes, it is not necessary for retailers to pass through distribution price structures to end consumers. Our view is if a retailer faces cost-reflective distribution prices, its incentive will be to respond efficiently (as that will help to manage the retailer's input costs and reduce its risk exposure). An efficient response by a retailer could take various forms including providing information to its customers; procuring or managing embedded flexibility resources on behalf of its customers; and/or adopting non-uniform usage charges or rebates. We note the MDAG Final Recommendations Paper provided a similar view:

> '… lack of retailer pass-through is not a barrier to flexibility per se, as long as the retailer is developing customer arrangements which see the retailer or flexibility aggregator manage the response on the customer's behalf.'[58]

We are not convinced that a direct intervention requiring retail pass-through into retail pricing would be in the consumers' interests. It could cause a significant change in the retail operating environment, which could negatively impact competitive pressures that drive innovation, efficiency and customer focus. Our current view is that retailers have a role to play in managing network input costs on behalf on their customers. We plan to expand our monitoring of retail electricity pricing through our current proposal to collect

[58] MDAG, Price discovery in a renewables-based electricity system: Final recommendations paper 2023 (ea.govt.nz), 11 December 2023, page 130, footnote 210.

retail data.[59] The retail data we receive will give us a greater understanding of the retail market, support evidence-based policy making and enable us to monitor policy interventions. We can also use this data to assess the availability of non-uniform retail pricing options and appliance tariffs and the end consumers' uptake of these pricing options. This project is expected to be progressed in late 2024.

(b) WEL Networks sought clarification on whether the distribution pricing reform sought to achieve cost-reflective tariffs or price signals that would lead to demand response curbing the large network capital expenditure over the coming decade.[60]

Our response: We encourage distributors to set cost-reflective tariffs. We expect that setting cost-reflective distribution tariffs will send price signals that will produce an efficient level of demand response and help defer network capital expenditure to an efficient extent.

(c) A small number of submissions felt the use of call-in mechanisms as a regulatory backstop could lead to poor consumer outcomes if such mechanisms were put in place before the issues were understood and there were practical actions to address.

Our response: We have not ruled out the option of using this mechanism, but we would fully consider possible unintended consequences before using it.

(d) There were a limited number of submissions on appliance tariffs allowing load control.

Our response: We encourage the use of load control tariffs (as noted in our Open Letter of September 2022),[61] and we encourage distributors to continue planning for pricing responses to significant EV penetration. This could include developing controlled EV charging tariffs with differentiated pricing.

5.12. Submissions on the use of profiles confirmed that this practice is unacceptable when metered data on consumption by time of use is available. However, there was no firm evidence presented of this practice taking place. We have since engaged with a number of electricity retailers to understand their use of profiling. These retailers advised that when they have access to time-of-use meter data, they provide that data to distributors and only make use of profiles when data is unavailable.

5.13. A number of submissions raised concerns around the cost implications from upgrading meters or reconfiguring smart meters to allow for greater availability of metered data on consumption by time of use. However, smart meter penetration is already relatively high, and we understand that smart meters are usually easily reconfigured to record time-of-use data remotely and do not require any physical intervention.

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59 Improving retail market monitoring: Clause 2.16 information notice | Our consultations | Our projects | Electricity Authority (ea.govt.nz)

60 The Boston Consulting Group forecasted $22 billion capital expenditure by the end of this decade.

61 Open letter to distributors about the distribution pricing reform, September 2022.pdf (ea.govt.nz)

5.14. Other submissions suggested retailers' billing systems may need to be upgraded to accommodate time-of-use data, which may impose costs on retailers. However, other submissions and comments made at our regional forums noted that, while some retailers' billing systems may require some level of upgrading, retailers have had sufficient time for this, and the cost of upgrade would not be significant.

Next steps

5.15. Based on the voluntary progress on assignment to time-varying distribution tariffs we have observed to date, we have decided to continue monitoring progress on this issue and to engage with individual distributors to understand their circumstances and encourage continued progress.

5.16. To encourage progress, we are considering providing the industry with guidance on tariff assignment. We expect to use tariff assignment as a measure for future distribution pricing scorecards. However, if progress on this issue slows, then we will consider using mandatory measures.

5.17. Following discussion with ENA, we have concluded that our activity in this area is unlikely to raise issues of consumer impact and energy hardship. The majority of residential ICPs are already assigned to non-uniform tariffs and more are expected to be assigned over time. Note also that retailers are not required to pass on distribution tariff structures to their customers.

5.18. We are still progressing our understanding of the related issues of retailers' use of profiles, or a single volume data point for total monthly consumption, for submission of consumption data to distributors. We will engage with distributors (via ENA) and retailers during May 2024 to better understand these issues and possible remedies.

6. Target revenue allocation

6.1. Key concepts such as the subsidy-free range need further development to ensure they are fully understood by everyone in the industry before we start testing the efficiency of target revenue allocations.

Context

6.2. As discussed in chapter 6 of the July 2023 issues paper, the first step in pricing is to allocate target revenue to pricing areas (if applicable) and then between consumer groups. Allocations should be subsidy free and managed to minimise harm and promote efficiency. Allocating target revenue between consumer groups is an important stage in the pricing process, and it needs to be actively and purposefully managed to promote efficiency. To this end, we need to ensure we fully understand subsidy-free ranges and move away from relying on complex accounting cost models.

Current situation

6.3. As noted in the issues paper, there is limited evidence of robust subsidy-free analysis or active, purposeful management of allocations.

Options proposed in July 2023

6.4. The options for target revenue allocation were:

(a) do nothing

(b) extend the practice note and scorecards

(c) prohibit or mandate specific approaches

(d) call-in target revenue allocation for review and approval.

Submissions received and our assessment of the submissions

6.5. We received 17 submissions on this topic: one from a retailer, three from consumers and consumer groups and 13 from 16 distributors (some distributors submitted together). Almost all submitters argued that the Authority needs to provide more guidance on this issue.

6.6. **Our response:** We agree with submitters that this is a technical issue that would benefit from more in-depth analysis. Our current view is that target cost allocation is less likely to create perverse incentives, by comparison with connection charges or high off-peak rates. We consider regulation is not required for target cost allocation at this time.

Next steps

6.7. We are considering developing a technical guidance note for distributors within the next financial year.

Appendix A Distribution Pricing Principles

(a) Prices are to signal the economic costs of service provision, including by:

i. …being subsidy free (equal to or greater than avoidable costs, and less than or equal to standalone costs);

ii. reflecting the impacts of network use on economic costs;

iii. reflecting differences in network service provided to (or by) consumers; and

iv. encouraging efficient network alternatives.

(b) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.

(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:

i. reflect the economic value of services; and

ii. enable price/quality trade-offs.

(d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

Appendix B Screening high-level options for connection pricing

B.1. In the issues paper, we introduced the three high-level options of:

(a) continuation – rely on monitoring and guidance, with reinforcement from reputational incentives provided through the scorecard process

(b) call-in – amend the Code to provide for targeted call-in and approval of pricing methodologies or certain elements of a methodology

(c) control – amend the Code to mandate or prohibit pricing approaches.

B.2. We have carried out an initial assessment of these high-level options against our evaluation criteria. We will revisit this assessment as appropriate (for example, if we consult again and receive further feedback).

Continuation

B.3. We have supported reform in recent years by publishing distribution pricing principles, a distribution pricing practice note and scorecard assessments that monitor and comment on distributors' pricing methodologies. The pricing principles are in effect voluntary, and we have relied on guidance and reputational incentives to encourage reform.

B.4. In 2023, we introduced 'progress against focus areas' as a scoring category for the scorecards and identified five focus areas. One focus area dealt with an aspect of connection pricing – distributors' response to any significant first mover disadvantage (FMD) issues facing customers who wanted to connect to their networks.

B.5. The continuation option could involve some mix of:

(a) guidance on application of the pricing principles to connection pricing

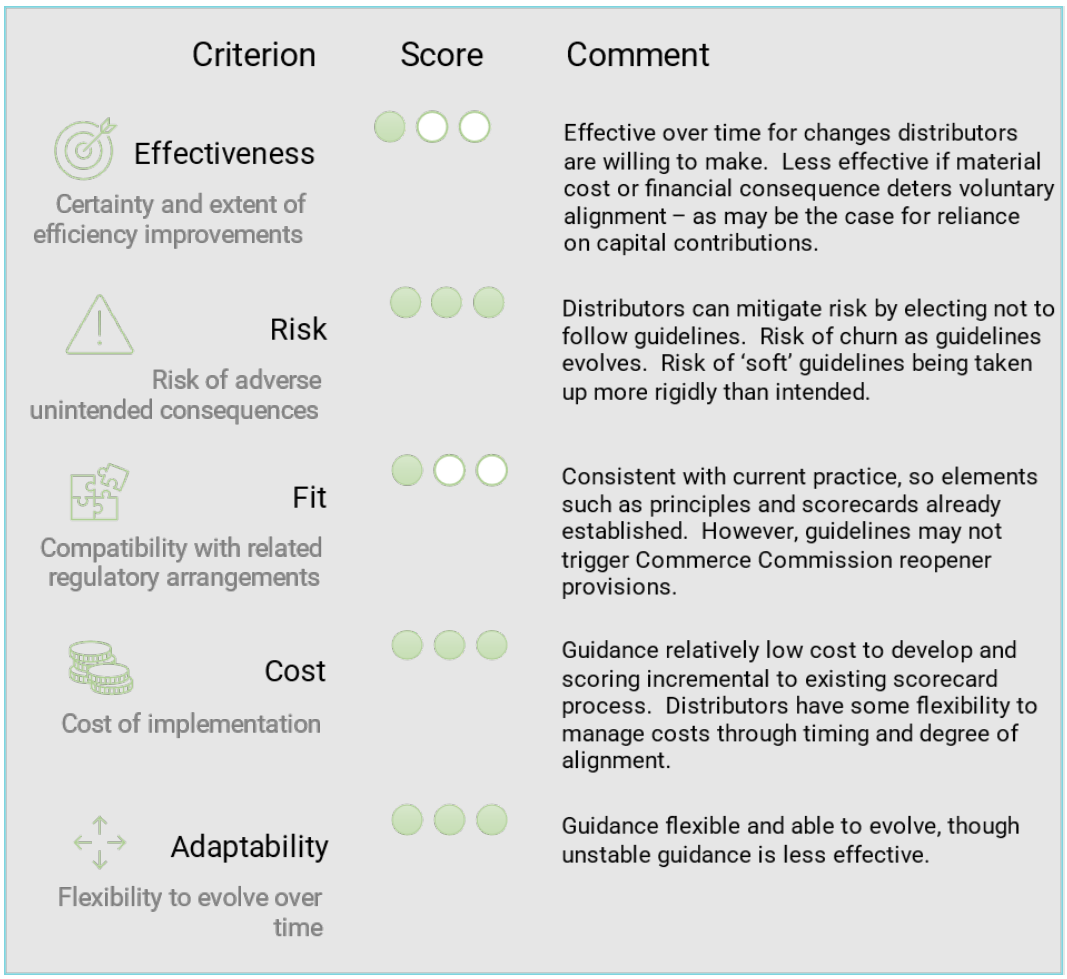
(b) extended guidance on technical matters, such as subsidy-free range concepts and their application

(c) identification of other connection pricing matters as focus areas for future scorecard rounds, such as demonstration of an efficient balance between connection pricing and use of system charges

(d) targeted engagement with the electricity sector and access seekers, for example, to promote consistency and identify and promote best practice.

B.6. Figure 6 below provides a high-level assessment of the continuation option against our evaluation criteria. We have assigned a score against each criterion. Note: More dots means a better score.

Figure 6: Assessment of continuation option



B.7. In summary:

(a) continuation is suitable as a counterfactual against which to refer to when developing the other options

(b) elements of the continuation option can complement any other option (For example, targeted control of one aspect of connection pricing could be complemented by guidance and monitoring of broader connection pricing practices).

(c) continuation is most effective for matters where voluntary alignment is not costly or otherwise unattractive to distributors.

Call-in

B.8. Targeted call-in was floated as an option in the issues paper.

B.9. The option could be considered as a variation on the AER's practice in approving tariff setting statements in Australia. It provides an intermediate option between control and guidance, allowing for more nuanced interrogation of specific issues, sector-wide or for specific distributors.

Figure 7: Assessment of call-in option

B.10. In summary:

(a) while the call-in option has merits and would arguably better align New Zealand with comparable jurisdictions, it does not offer a timely or cost-effective method of addressing connection pricing issues

(d) accordingly, we plan to set this option aside for now.

Control

B.11. Targeted control would involve amending the Code to directly control an aspect of connection pricing. For example, amendments could:

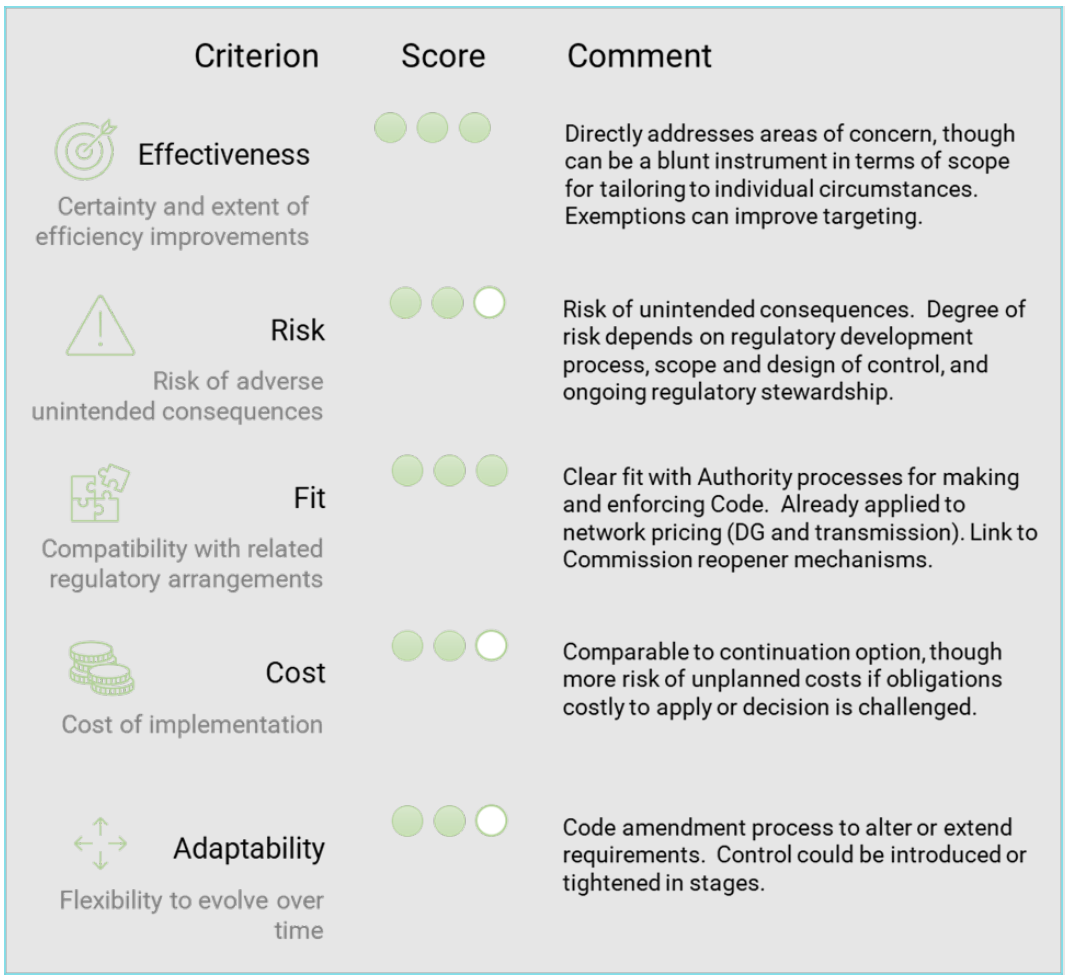
(a) require or prohibit a particular approach or outcome

(b) set upper or lower bounds on particular outcomes

(c) apply the above broadly or only to certain sizes or types of connections

(d) provide exceptions or carve-outs to requirements.

Figure 8: Assessment of control option



B.12. In summary:

(a) the control option has merit, is our preferred option and warrants further development

(b) accordingly, we plan to develop and evaluate a range of control options.

Glossary of abbreviations

AER	Australian Energy Regulator
AMD	Anytime Maximum Demand
Authority	Electricity Authority
Code	Electricity Industry Participation Code 2010
ENA	Energy Networks Aotearoa
EV	Electric vehicle
DDP	Default price-quality path
FMD	First mover disadvantage
GXP	Grid exit point
HEG	Horizon Energy Group
ICP	Installation control point
LCC	Large customer contract
LFC	Low fixed charge
LFC regulations	Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004
LRMC	Long-run marginal cost
Ofgem	Office of Gas and Electricity Markets
TOU	Time of Use
WE	Wellington Electricity