October 2022

Distribution Pricing: Practice Note

Second Edition v 2.2, 2022

ELECTRICITY AUTHORITY
TE MANA HIKO

Contents

Wider information relevant to this Practice Note

The following relevant documents are available on the Electricity Authority's website's distribution pricing pages:

- The 2019 distribution pricing principles
- Distribution Pricing Scorecard - Interpretation Guide
- 2021 scorecards and the covering reports.

The *Distribution Pricing: Practice Note 2019* remains relevant and valid.[1] For ease of reference the 2019 guidance is included in this document as Appendix B.

The April 2022 version 2.1 of the second edition is a minor update to the December 2021 2nd edition. The update provides additional guidance relating only to locational pricing, which can be found at (new) paragraphs 89, 90 and 91. Numbering for the paragraphs that follow has therefore been updated.

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[1] The 2019 Practice note remains valid with the exception of 2019's Figure 1, which was updated by Figure 1 in the 2021 2nd edition

This October 2022 version adds guidance on Distributed Generation in the text box "How capital contributions apply" and adds Appendix C on TPM transmission pass through.

Part 1: Purpose

This Part lays out the purpose of the updated Practice Note and its expected future updates.

Purpose and overarching principles

1. The purpose of this 2nd edition Practice Note is to provide further guidance to assist distributors with applying the 2019 Distribution Pricing Principles.
2. The 2019 Distribution Practice Note remains relevant and valid and so is appended to this 2021 2nd Edition.[2] The guidance has been refreshed to now also provide:
   a. further guidance on the application of the pricing principles
   b. additional guidance and illustrations on the future course expected for distribution pricing
   c. timeframes expected for reform of distribution pricing
   d. more detail on what the Authority considers 'good looks like': outcomes driven by pricing reform from different stakeholders' perspectives.

Future updates

3. As reform of distribution pricing evolves, we expect to review and update this Practice Note again. This guidance is intended to be a 'living document' for the industry to reference in implementing efficient distribution pricing. This means that this 2022 2nd edition contains parts which may be superseded in the future as pricing reforms and conditions develop.

Forward engagement focus

4. Stakeholder feedback on the draft version of this 2nd edition Practice Note has highlighted key matters on which the sector seeks ongoing engagement and further clarification:
   a. expectations of pricing reform opportunities and progress during the phase out of the Low Fixed Charge regime
   b. customer impacts in regards of locational pricing and rate of transition to new pricing
   c. the merits (or not) of pass-through of price signalling for both transmission and distribution pricing.
5. The Authority considers that these matters are best progressed through broad engagement with stakeholders over 2022 and 2023. The intention will be to build on combined industry knowledge expertise and experiences to produce a shared understanding and agreement, rather than being specified through this 2nd edition of the Practice Note.
6. Outcomes of engagement and discussion on the above matters are likely to inform the next edition of this Practice Note.
7. Stakeholders have also highlighted data access for low voltage network congestion analysis to inform price setting is a concern. Consideration of this matter lies within the Authority's parallel workstream '*Updating the regulatory settings for the distribution sector*'. Concerns raised have been shared within the Authority and given the importance to pricing reform, the workstreams are collaborating.

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[2] The 2019 Practice note remains valid with the exception of Figure 1, which was updated by Figure 1 in the 2021 2nd edition.

The 2019 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.

Part 2: Expectations on the application of the distribution pricing principles

This Part sets out the Authority's expectations for how the principles work to send appropriate pricing signals, how they work with asset management practices, capital contribution policies and lead to efficient pricing outcomes that benefit customers.

8. The primary role of efficient pricing is to correctly signal the most efficient use of the existing network and, where appropriate, to reflect the cost of future network investments or the application of non-network investments – the latter either by the distributor[3], its end-users, or other participants. By encouraging more efficient use of and investment in electricity networks, efficient distribution pricing leads to relatively lower prices for electricity consumers in the long-term. Promoting efficient electricity infrastructure investment will be particularly important as New Zealand electrifies its transport fleet and industrial processes over the next 30 years to support its transition to a low-emissions economy.
9. The *Distribution Pricing: Practice Note August 2019* signalled that efficient pricing requires a different approach to price-setting. Traditional price-setting allocated target revenue to consumer groups then developed prices for each group.
10. Efficient pricing over the longer term for a distribution network involves a process to develop cost-reflective allocations and using price as a signalling mechanism (where needed), and then (given the target revenue to recover) allocating residual costs in a least distortionary manner.
11. Figure 1 below illustrates the components of efficient distribution pricing. This graphic supersedes the version in the *Distribution Pricing: Practice Note August 2019* as we believe this version better illustrates the cost allocation, price signalling and final price setting approach.
12. Since April 2020 all distributors under Default Price-Quality Path and Customised Price-Quality Path regulation have had their revenue set via a revenue cap rather than a price cap. This approach removes the uncertainty associated with demand fluctuations interfering with calculating target revenue, and so provides more latitude for how distributors set prices and progress their reforms towards efficient distribution pricing.
13. The Commerce Commission noted in its Reasons Paper supporting the latest Default Price-Quality Path setting, *"[i]mplementing a revenue cap (as opposed to the previous price cap) will give distributors the flexibility to price in ways that offer more choice to consumers and that enhance incentives for energy efficiency and demand-side management."*[4] Distributors can now undertake more active price signalling to consumers to both encourage usage in times of low network congestion or demand, and to discourage usage during times of network constraint. This also applies to signals to suppliers of energy (via localised generation activity or distributed energy resources) where prices can signal when and where it is efficient for the network to receive energy, and when it is not.

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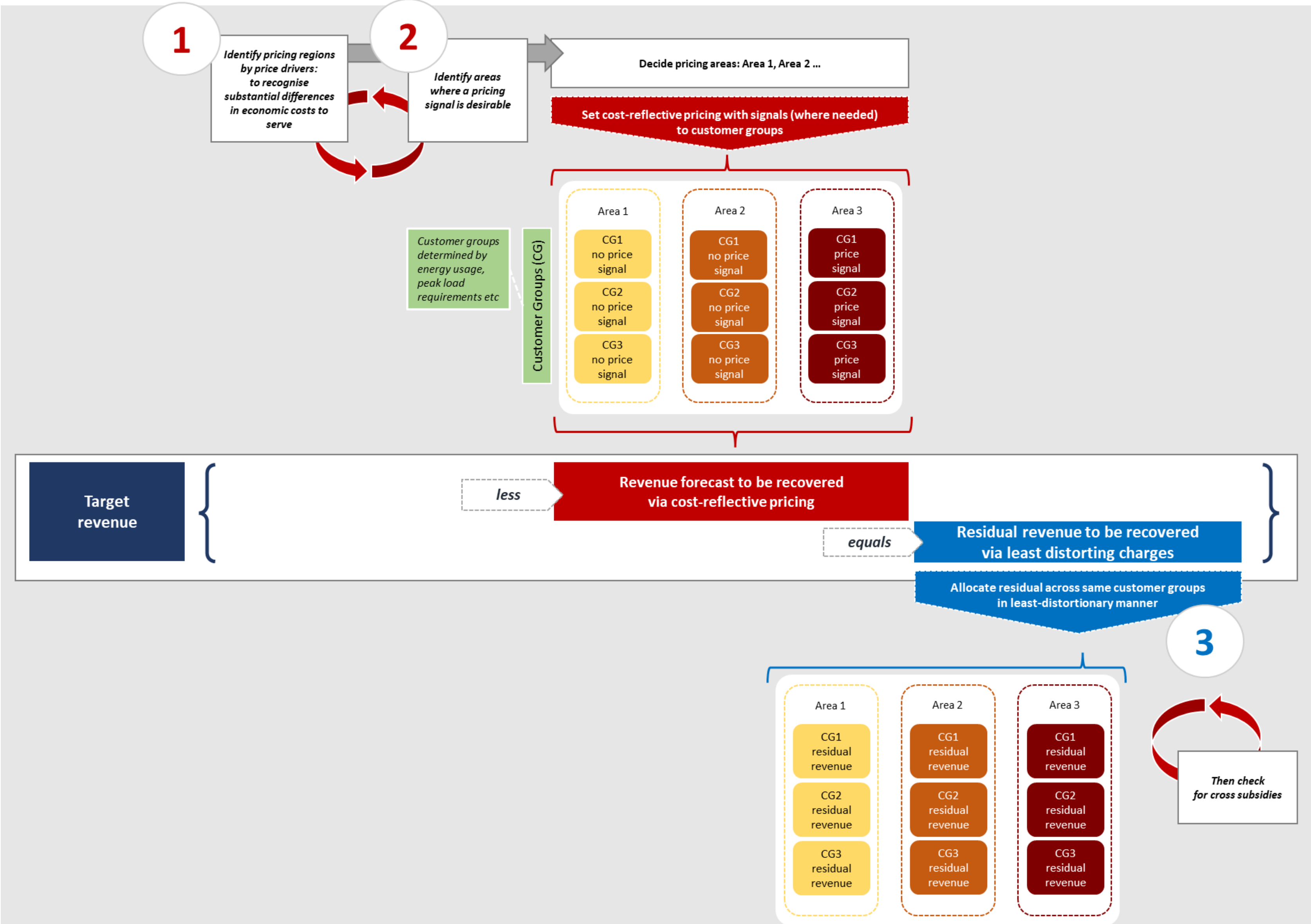
[3] Distributor investments in non-network alternatives is being considered as part of the *Updating the Regulatory Settings for Distribution Networks* consultation (August 2021).

[4] *Default price-quality paths for electricity distribution businesses from 1 April 2020 – Final decision*, Commerce Commission, 27 November 2019

Figure 1: Steps to setting efficient distribution pricing: 1) cost drivers and 2) any price signalling and 3) least distortionary residual allocation



What is expected of cost-reflective pricing with price signalling?

Cost reflective pricing

14. Setting prices to recover the economic cost of delivering electricity to a group of customers is the traditional definition of 'cost reflective'. That is, cost allocations should reflect the underlying drivers (causes) of cost and should recover the cost of sunk or already invested infrastructure, can include a price signal, and should be free of cross-subsidies. The price signalling element can also reflect the cost of providing new network capacity to customers, and, within the constraints set by the distributor's maximum allowable revenue, may at times be an even stronger signal (see paragraph 33 below).

15. The 2019 Distribution Pricing Practice Note's section 3.2 contains for more detailed guidance on considerations for allocating costs according to known cost drivers (The 2019 note is at Appendix B of this 2021 2nd Edition).

Why use a price signal?

16. A price signal is intuitively understood as the most visible input to the question *'am I willing to consume now at this given price?'*. Common price signals that people often deal with are hotel prices and airline tickets. With low supply and high demand we expect a higher relative price, and *vice versa*. A price signal creates a situation where choice can (usually) be exercised - do I consume now, do I change my consumption pattern, or do I find an alternative? It incentivises (rather than instructs) consumers, retailers, and flexibility traders to determine their willingness to be active in shifting demand.

17. A well-designed price signal provides a cost-reflective measure of the impact that an additional marginal unit of energy has on the network and can signal the opportunity cost of future necessary investments to accommodate increasing demand. Across a system or network the various price signals work to balance supply and demand – now and in the future. There is a continuum of people exercising their choices of how they value their marginal energy: as price rises, fewer people will keep consuming. These decisions are invisible to the distributor and often intuitively made by the consumer, or on their behalf, according to a multitude of individual preferences. As technology evolves demand shifting may become more invisible to the end consumer. Why someone values the energy they use is not necessary for a distributor to understand in order to provide efficient price signals.

18. Price signalling must reflect the state of the network and will therefore range from sending no signal, to a signal that incentivises a particular action. Its core aim is to signal physical loading on the network relative to capacity. When there is no (actual or anticipated) congestion the price signal should not be influencing how consumers use the network.[5] A peak signal could create a distortion that is inefficient and harms customers (eg, if it incentivises people to turn down, or off, heating) if there's actually no congestion.

19. Instead, efficient pricing for a network with a flat or falling demand and no constraints could be a fixed charge that simply recovers the invested capital without influencing network use. If recovery via a fixed charge is not available, a second-best option may be a completely flat tariff structure that does not vary by time or amount of energy consumed.

> Illustration: For a feeder that is congested every weekday evening, the distributor sets higher prices during that time. If this doesn't ration demand the distributor could:
>
> - keep sharpening the signal
> - work to remove any barriers that are causing the signal to not 'get through', including considering if the cause is lack of pass-through or other response from retailers, in which case the distributor could seek to agree a solution with those retailers or flexibility traders
> - consider if the customers are simply not responsive to price. In the long term, if consumers' willingness to pay for a network upgrade exceeds the cost of the upgrade, then it would be efficient to upgrade the network.

[5] Network congestion means that network capacity is not adequate to meet demand at a particular network location at a particular time. It does not mean the same thing as peak demand on the network.

By contrast, a network with congestion could address this by increasing prices during constrained periods. The increase (the signal) needs to be enough to:

a. incentivise enough demand reduction to remove the congestion, or

b. to signal that further investment in infrastructure or generation will be needed to accommodate increasing demand.[6]

20. Getting the right outcome for all customers (including those choosing to increase their electricity consumption), distributors, and other participants requires that those who stand to benefit from network (or network alternative) investments should shoulder the bulk of the cost, and those that are most able and willing to adjust their demand in response to price changes have an opportunity to monetise their choice by changing their consumption.

21. There is an interplay or circularity to allocating costs reflecting underlying cost drivers then setting a price signal - as indicated by the circular arrows in Figure 1. These arrows illustrate the aim to achieve pricing principles a) i) to iv) for cost allocations (including signalling) that applies to a customer group[7]:

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

reflecting the impacts of network use on economic costs

reflecting differences in network service provided to (or by) consumers, and

encouraging efficient network alternatives.

22. To assess against these principles, it is necessary to complete (per figure 1) the first segmentation step then apply any desired price signal then allocate the share of the residual - *then* check whether there is over or under-recovery meaning the price signals might not align with pricing principle a) i) – that prices should be subsidy free.

23. By using prices to balance network usage, a distributor can ensure its network design is appropriate for customers' needs and avoid or delay investment in new capacity until necessary. Price signalling, within the constraint created by maximum allowable revenue, is a key component of good asset management.

24. The focus of this Practice Note is on reforming distribution prices for residential and small commercial customers.[8] Residential customers comprise 85% of total national ICPs[9] and this accounts for the bulk of the length and density of distribution networks.

Price signalling operates differently in the short and long term

25. Appropriate price signals will better manage usage of the network across the short and long term. Pricing can help ensure networks make the right investments at the right time in network and network alternatives, leading to lower overall costs to consumers in the long run: a clear consumer benefit.

26. Efficient short-term price signalling means charges could rise to ensure consumption reduces until congestion is no longer an issue on that part of the network, in the short term. An example of this is where a feeder is becoming congested for a short period each year, eg, for a few nights during the coldest part of winter, for a few hours per night. Prices are not the only method of signalling - a distributor could instead (or also) offer a 'first off' option or a demand response option to help it manage network congestion, usually in return for a payment or a discount to charges.

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6 The Authority recognises that some consumers are not responsive to price and so price signalling can exacerbate affordability issues. The pricing principles include considering impacts on consumers. The Authority also supports MBIE's work on energy poverty.

7 For further guidance on these principles see section 3.2 of the *Distribution Pricing: Practice Note August 2019*

8 Sometimes referred to as 'mass market' customers

9 Electricity Authority, EMI data

27. It is efficient for a distributor to use such price signals to delay the necessity of investments, until the cost of a network upgrade (or alternative solution) becomes economically justifiable - ie, the value to consumers exceeds the cost. In this way, price signals lead to efficiency in the long-term. Once an investment is made to accommodate increasing demand and relieve congestion, pricing signals designed to limit use on that part of the network would likely be removed. The cost of a recent investment could be allocated across the whole network; however a more efficient pricing approach could mean a more granular cost-reflective approach that allocates long-term costs of a new part of the network to the customers connected to it (per step (1) in figure 1).[10]
28. Many distributors are pricing according to these concepts – so managing short- and long-term pricing and investment decisions via their asset management planning systems and tools which assess project investment viability. Our concern is that for some distributors price signals may need to become stronger to be confident that long-term decisions are in the best interests of customers.

The window of opportunity concept for designing effective prices as we electrify

29. Through the consultation on this Practice Note we were provided with a concept – the 'window of opportunity' that we believe assists in understanding the time element involved in efficient pricing. The 'window' describes a time dimension of anticipated congestion that is created by the interplay of increasing demand and cost reflective pricing and price signalling, and investments by distributors, customers and flexibility traders.
30. The window is determined by both a distributor's ability to respond with new investment (considering the lead time required to design, procure and build new infrastructure) and the timing of any customer investment.
31. Understanding the timing of these decisions by both distributors and customers creates a 'window of opportunity' where customers' responses to price signals can be used to efficiently defer or avoid network investment.
32. The strength of the price signal should reflect how far into the future the network constraint is expected. Sending a strong price signal too early may provide an inefficient incentive for customers' investment in distributed energy resources (DER). Conversely, sending a signal too late may not leave enough time for customers to respond before the network becomes constrained and the only practical option becomes network investment.
33. Applying the concept of a 'window of opportunity' leads to three potential pricing scenarios:

Scenario 1: Immediate Response Required

If demand is expected to create a network constraint before new infrastructure can be built, it is likely that a customer response and/or flexibility services will be required to help manage demand until such time as new infrastructure can be constructed. A strong price signal could manage demand to create the necessary response, as well as to support the entry of flexibility services.

Scenario 2: Cost-reflective price signal required

In situations where the network is expected to become constrained within the 'window of opportunity', a cost-reflective price that signals the future cost of network investment or the cost of demand-side investment (if that is lower) can influence consumers to make choices about their consumption behaviour and investment in DER.

Scenario 3: No price signal required

If demand is not expected to create a network constraint within the 'window of opportunity' then no immediate price signal is required.

[10] This could be recovered as a fixed charge that is not intended to influence use of electricity, comparable to a benefit-based charge (in the transmission pricing context).

34. The specific timing of a window of opportunity will be determined by each network's characteristics and asset management framework.

35. It is important to also note at this stage that sending a price signal is not necessarily designed to ensure a demand response. Rather, a price signal is designed to ensure customers *consider* whether they want to adapt their demand, or not.

36. Sending a strong price signal where no network need is identified would result in inefficient pricing (see section *Unnecessary signalling should be avoided*). In the other direction, some distributors may want to send a weaker price signal as a temporary step where they believe that it will assist with developing customer familiarity with different pricing structures and help manage the customer impact in the future when the stronger signal may be needed.

37. The timing and purpose of a price signal therefore should be aligned with the strength of the signal. This is apparent in following sections where there is discussion of the risks of over-signalling and also an acceptance that weaker signals can serve a 'familiarity' purpose.

Price signals will vary across a network and across customer groups

38. An efficient price signal may vary across the network's footprint, and across time (over a day, week, month, or season). Depending on who is connected where, efficient price signals may also vary across customer groups. In contrast, a network with no congestion may not need price signals to shift demand across a day.

39. Time-of-use (TOU) tariff structures can be effective in reducing congestion on a specific part of a network during times of peak load. But because consumers differ, a peak signal to some consumers might be very effective, and the same signal could have zero effect on other consumers. So, balancing a network in the short-term may mean a different price for different parts of the network at different times. A blunt TOU pricing structure applied across a whole network (including parts with no congestion) may not be a useful signal. It could incentivise inefficient demand reduction or encourage inefficient investment in DER.

40. Appropriate consumer groupings require judgment by each distributor - sufficiently granular to price-signal congestion to the right consumers, but not so many that it becomes overwhelming for the distributor, retailer, flexibility traders and the wider market to understand and implement. Future technology may enable individualised price structures, but that is some way off and going to that granular level may not actually be desirable in other ways.

41. Distributors must trade-off between finely targeting price signals and pricing structures that are implementable, both for the distributor and also for retailers passing on the price signal. Whether the balance is right can be measured by how effective the price signalling is at achieving its intended goal.

    a. At times it may be appropriate to send a price signal where no current congestion or network need is evident, but the distributor's network understanding and trend analysis suggests that it will be required in the coming years. As mentioned above, this advance signalling has the benefit of helping customers to get accustomed to responding to signals.

    b. These signals, sent in anticipation of a future need, must be implemented carefully and we expect them to be monitored closely and assessed for undesirable or distortionary outcomes.

42. We do not expect to see one size fits all 'cookie-cutter' price signals, but rather distributors working to deeply understand both network conditions and customer demand patterns – now and over time. This process, we acknowledge, can take many years, and so pricing reform will rely on a distributor's willingness to take appropriate actions now while building its information base and understanding to inform future pricing.

43. A distributor should understand its assets, and which assets serve which consumers, if pricing is to avoid unintended cross-subsidies from one part of a network's consumers to other consumers.

Unnecessary signalling should be avoided

44. We try in this Practice Note to identify and illustrate what 'good looks like' and so for completeness we can also describe unnecessary signalling. In the simplest terms, an unnecessary price signal is sending one when it is not required, the signal does not meet a determined need[11] or it's the wrong signal.

45. Examples include, but are not limited to:

    a. using a high variable charge component when no congestion is evident

    b. using a price signal across parts of the network that are not congested and/or which applies at times when no congestion occurs

    c. leaving a pricing signal in place after network investment has been completed and congestion is no longer an issue.

The strength of signals, and avoiding over-signalling

46. Price signals should not normally exceed the forecasted cost-reflective level of the future network investment required to respond to current and forecast demand. A price signal up to this level can be an efficient means of avoiding or deferring that future investment. The efficient price might also be well below this level, for example a cost-reflective price could signal the cost of a demand-side investment and encourage consumers to make choices about investment in DER.[12]

47. Sending a strong price signal is necessary and acceptable for the time period that the price signal is required.

Complexity

48. The distribution of electricity is a largely unseen yet relied upon service for customers, and over time, an expectation appears to have been created that pricing should be simple.

49. However, as we transition to low emissions and the economy electrifies further, future technology and service offerings available to customers are likely to become more complex, some distributors may elect to design a 'fit-for-purpose' pricing response. Increased complexity to better meet customer preferences could be accommodated by technology and the potential rise of flexibility traders filling a gap between customer desires and supplier needs. We expect the level of complexity and range of applicable pricing structures will rise and fall over time.

50. We expect trade-offs when balancing complex pricing with other aims. For example, a theoretically most efficient price signal for a certain situation may create confusion due to its complexity, and there may be circumstances where a theoretically imperfect pricing structure is the most effective way to generate a desired response.

51. To simplify outcomes and impacts on customers, distributors and retailers need to work together to provide clarity for customers, ensuring that any aversion to pricing complexity does not slow electrification. This is an area that is often encountered and responded to - constructively - after a price change impacts a customer who then complains. Extending this good work addressing 'outliers' with detailed explanations to a new norm of ex-ante explanations to customers is encouraged.

Pricing signals in summary

52. By way of summary, designing effective pricing signals needs to follow a process where distributors seek to understand the following:

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11 For the avoidance of doubt, any time in this paper we refer with approval to a peak charge or TOU pricing (or any other price signal), we are referring to such a price signal that is required due to actual / imminent network congestion.

12 A possible exception to the above guidance could be that an immediate strong price signal - such as a critical peak price – could be used to efficiently ration use of a network during periods of congestion. This tool may become more prevalent in time if retailers choose to offer more variation in pricing plans for some residential and small commercial customers.

a. their network design: what assets do they have, and where?

b. flows relative to capacity: where is demand changing and congestion occurring, or expected?

c. who's using the network and how: do assets support all or some customers, and which customers will benefit from new investments?

d. whether a price signal is useful, to influence users, or if prices should simply seek to recover costs in a manner that does not influence network usage (eg, a fixed daily charge) and/or reflects who is benefiting from specific parts of the network: a least distortionary cost recovery exercise.

Why? Because efficiency in network investments will lower prices for customers in the long-term

53. The purpose of effective price signalling is to provide efficient outcomes. Efficiency is shorthand for what it produces: long-term benefits for customers.

54. The electricity sector is seeing rising prices across all facets of traditional generation, transmission, and distribution. As the backbone of the electricity industry the distribution sector has a large ongoing investment programme already, to maintain, grow and replace existing networks; many with creeping age profiles and pressures to remain within regulated reliability and quality of supply requirements. Investments add costs to consumers.

> The goal of efficient cost reflective prices is that over the longer-term consumers will obtain the greatest value from their consumption of electricity, new investments will be at the right time in the right places, and consumers will pay less than they would have if prices were not efficient.

55. The 2019 Electricity Price Review found that there was no reason now to target distributors to fundamentally reduce their costs or review their prudent operation. However, if distributors overlook the pricing part of their toolkits, they risk over-investing in capital to lift capacity. Effective price-signalling can help delay or avoid additional investment.[13] This keeps prices relatively lower for consumers in the long-term.

56. Right-sizing of investments for efficient network performance is a hallmark of the sector's engineering objectives, and most distributors are keenly aware of and anticipating the expected forthcoming 'new energy future' that will see their networks utilised more fully and by a wider range of participants than currently seen. This was a key component of the ENA's 2017 *Guidance on Pricing Reform*.

57. Efficient pricing supports innovation. If pricing is cost reflective this also allows distributors to target traditional network and more innovative non-network solutions. It allows for other participants, such as flexibility traders, to be involved and help to deliver a low emissions future. It leads to better use and investment decisions by consumers, including in distributed energy resources. In the context of technological changes and the substantial role that electrification is set to play in the very near term of New Zealand's low emissions future, distribution pricing reform is now critically urgent in shaping the success of achieving these goals.

Efficient pricing will lower prices in the long-term, for all

58. Efficient distribution pricing will not lower the price to every customer in the short-term. Managing the increases and decreases in network charges as they are re-balanced will require distributors to engage with customers. Retailers too will face concerns from customers affected by pricing reform, and we see that this will strengthen the partnership between distributors and retailers to deliver satisfactory outcomes to end customers. The Authority also has a role to assist distributors, retailers, and customers with this transition, and we expect that a collaborative approach will accelerate reform of distribution pricing.

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13 The Authority recognises that this is a balance: if consumers' willingness to pay for a network upgrade exceeds the cost of the upgrade, then it is more efficient for the network upgrade to proceed.

59. Allocating the costs of the existing network will have different challenges to price signalling with respect to future investments. Changes to existing pricing structures may create a sense of unfairness by customers who face higher charges due to signals, location, economic costs of the part of the network they are on, and for some the fact that prices have changed when they have a history of expecting price stability.[14] There are options available to distributors to mitigate this impact. The target in any case is not necessarily to remove all cross-subsidisation,[15] but rather to provide customers with the ability to respond to price signals in their most valued manner.

60. Allocating future investment will also be critically important. Estimates of the capacity needed to deliver New Zealand's low emissions future means we can expect substantial investments over the next decades. It is imperative that efficiency is at the core of future investment decisions. We expect that those who are expected to benefit directly by a network enabling increased electrification will be allocated the related costs accordingly. By pricing efficiently distribution networks will help to position New Zealand for a lower cost transition to a low-emissions future by ensuring the best use of existing and future infrastructure.

Considering the impact of price changes on customers

61. Bill shock and impacts on customers are strong motivators to customers' acceptance of change, and the Authority therefore does not wish to create a rapid move to efficient prices that attempts to remedy decades of inaction within an unreasonably short time period.

62. The 2019 Distribution pricing principles addresses this:

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

63. The 2019 Practice Note provides additional guidance on the application of this principle (see Appendix B).

64. To reiterate, the reason that efficient cost-reflective pricing is important to all customers is because the counterfactual - of unrestrained inefficient network investment - would increase the total costs of the system, and those inflated costs could potentially fall on parties who do not use or benefit from the investment.

65. We do not expect that providing welfare support to customers is the primary role of distributors and retailers, although we acknowledge this is often done by both. Energy hardship is a growing concern and cost reflective pricing and good price signalling will assist with keeping prices as low as they can be, overall and in the long-term, by ensuring that the right investments are made at the right time.[16] It will also provide greater visibility to allow better targeted support from Government agencies managing welfare outcomes.

66. Price shocks are not a desired outcome of pricing reform, and the Authority is cognisant of the need for prices to evolve on a journey towards efficient outcomes, rather than rush to an endpoint. We will have some patience with price reform once it is clearly underway, to allow customers to adjust, technology to assist, and distributors and retailers to manage good customer engagement and to learn and evolve towards what is best for their networks and customers.

67. The Authority expects to see steady progress to smooth customer bill changes over progressive years to move closer to an acceptable level of cost-reflectivity. Part 5 of this Practice Note outlines the Authority's expectations for the timing of price reform.

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14 Although these prices are mediated by retailers so some customers may not see these changes.

15 The Authority recognises that where a very strong price signal is desirable, the subsidy-free principle may not always be attainable.

16 That is, networks invest in the extra capacity at the point at which consumers are willing to pay for it, compared with poorly targeted or early upgrades that result in relatively low benefits for the consumers that ultimately pay for them.

Pricing is part of a distributor's Asset Management toolkit

68. Good price signalling is expected to be a well-used tool in the distributor's toolkit for managing its network. It should form a part of, utilise and feed into, the Asset Management Planning process. In a strong Asset Management framework customer choices and ability to influence future investment are key parts of understanding the context of the network. Consultation on network developments and choices for alternative investments (network and non-network) have a clear pricing component and we expect they are part of discussions both internally and externally for efficiently and prudently managing investments.

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

Capital contribution policies need to align

70. How expansion or upgrade of networks is funded is often the nexus of asset planning and pricing, as expansion and upgrade investments indicate that customer needs of the network are currently not being met. Capital Contribution[17] policies are a disclosure requirement under Commerce Commission regulation.[18]

71. Currently there is no regulatory oversight of the content, design or intent of these policies which has led to distributors having a wide range of approaches. Without a single overarching goal of contribution policies – such as to recover the proportion of costs directly related to the beneficiary - there is the scope for significant cross-subsidisation and inefficient investment.

72. The role of contribution policies is another relevant question connected to the Authority's distribution pricing reform work. We expect to see all distributors bringing their contribution policies within the scope of their pricing structures and aligning with the Pricing Principles.

[17] Otherwise known as a Customer Contribution, Customer Connection policies

[18] Section 2.4.6 of *Electricity Distribution Information Disclosure Determination 2012,* Commerce Commission

Part 3: Expectations on pricing structures

This Part sets out the Authority's expectations for how distributors segment their networks for pricing purposes – in location and time and how different approaches to pricing structures can apply.

Trade-offs abound in the journey to reform distribution prices

73. Due to the differences between networks now, and the paths each will take in the years ahead as the country responds to the challenge of the low emissions future, as well as different evolutions of customer demands and consumption patterns, it is not possible to establish a single blueprint for efficient pricing for all networks.

74. In recognising that every network is different the Authority accepts that trade-offs will impact networks differently and be managed differently, in accordance with how each distributor plans its pricing reform.

75. In setting broad expectations below, the Authority also recognises that some distributors may, at times, adopt pricing that appears contrary to a fully efficient price signal. This may be for example to manage customer impacts or to allow customers time to acclimatise to and understand new price signals – during a transition time period. We expect that each distributor understands the trade-offs they are making and is transparent about the underlying rationale for decisions made.

76. In a similar vein, there will always exist a tension between what we're advising each distributor to be cognisant of, and distributors applying their own judgement on what is best for them and their customers. For example, on decisions between pricing structures that are highly efficient and complex (so maybe difficult for retailers and customers to understand and quickly respond to) compared to a less efficient set of pricing structure that is more easily implementable, and understandable, and so more likely to achieve the intended customer response.

77. As signalled, the Authority plans to engage more closely and regularly with the sector, through formal and informal channels, and so we believe that uncertainties created by trade-offs will be able to be dealt with over time.

The optimal level of pricing granularity will change over time

78. The level of granularity with which a distributor chooses to segment its network by time (temporal), geography (spatial) and customer grouping will require an evolution of pricing structures that keeps pace with technology, trade-offs between efficiency and customer acceptance,[19] and the responsiveness of customers.

79. The need to improve granularity now is clear – price changes currently happen annually (albeit they could be changed more frequently, and in time this may become desirable) and so delaying segmentation and trialling or implementing new pricing structures costs time. The pace of change in technology and demand pattern changes is accelerating, and time is not something that distributors may have the luxury of.

80. We expect to see distributors undertake 'no regrets' work now - from understanding the flows on their networks, and the context of current prices on their networks, to trialling the efficacy of reformed price structures. We acknowledge that for distributors that do not face congestion now (and don't expect it soon), reform may simply mean moving to higher fixed charges and reducing variable charges, once LFC regulations allow.[20]

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19 While customer acceptance is not part of the Authority's mandate, we acknowledge that it plays a role in distributor and retailer pricing decisions.

20 The impact of the LFC regulations is understood to be a significant block to some distributors in their work to accelerate reform. In terms of efficiency outcomes for price signals, as measured through the Authority's annual scorecards, it is difficult for a distributor to score at the top end

81. For other distributors, increasing the granularity of network segmentation is an important first step to ensure that price signals become better directed. As noted in MIT's *Utility of the Future* paper *"Granularity matters. The prices and regulated charges for electricity services vary significantly at different times and in different locations in electricity networks. Progressively improving the temporal and locational granularity of prices and charges can deliver increased social welfare; however, these benefits must be balanced against the costs, complexity, and potential equity concerns of implementation."* [21]

82. Economic cost-price signalling takes a degree of judgement - to segment the network based on an evidence and data-driven assessment of what is practical and implementable, and then to implement pricing signals appropriate to each group. Access to relevant and accurate data to identify both congestion and consumption patterns can be difficult, but we are observing distributors retailers and meter owners making headway in reaching agreements[22]. We expect this challenge to decrease over time as access to information improves.

83. In reforming distribution pricing there is a necessary feedback loop that the Authority expects to observe as it is a necessary part of continual pricing reform: analysis, understanding, trialling, implementation, observation, and adjustment.

Locational pricing?

84. Geographical segmentation ranges from viewing the network as a whole through to considering individual ICPs. It is well understood that the cost-to-serve of each ICP is different, and the most granular, theoretically efficient cost-reflective pricing would allocate to that level (ie, real-time locational marginal pricing).[23] However, it is currently impractical and might ultimately be undesirable (in terms of overhead efficiencies and consumer impacts) to attempt such precision. Some form of segmentation is therefore required.

85. Many distributors have established geographical pricing regions reflecting significant differences in cost to serve in the long run. These are sometimes a result of historical acquisitions (a distributor buying networks in other regions), reflect an historical engineering view of the network, reflect a group around a GXP or a zone's substations, or reflect network density (ie, a rural area and an urban area). Practical segmentation of a network for efficient price signals is likely to be achievable at a zone substation level, recognising that sub-networks are interconnected Usually these may not be too different from existing pricing regions, but for some distributors zone-substation-regions may be more granular than presently used. If distributors have systems and data to segment to a deeper level, and if this seems useful for an efficient cost-reflective price signal, this should be done.

86. Distributors are expected to be able to sum the invested capital in each segment, along with recording the ongoing maintenance of it. This financial cost view of the network then sits alongside network performance standards and usage patterns to produce an economic cost of each segment's energy use.

87. We understand that currently there is a wide range of abilities across distributors (and sometimes within a distributor's network) to understand footprint granularity. Reform towards cost-reflective pricing requires this understanding to improve for many. How far segmentation should go will vary but should be to a point where the materiality of differences in price signalling or cost-reflectivity between segments is small enough to warrant no further segmenting. Footprint granularity is not a

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of the range in this category with the LFC regulations in place. Understanding specifically how LFC restricts implementing better price signals is individual to each network and we expect that distributors are clear with the Authority where these limitations occur and how they expect to respond as the LFC regulations are phased out.

21 *Utility of the Future*, MIT, 2016, https://energy.mit.edu/research/utility-future-study/

22 This area is being considered as part of the *Updating the Regulatory Settings for Distribution Networks* consultation (August 2021).

23 Distribution network level locational marginal pricing has been investigated globally and some research has been undertaken in New Zealand to understand its potential reach and efficacy, especially in the widespread penetration of decentralised DER. The role of distribution locational marginal pricing is not a current consideration for the Authority.

one-off exercise, as usage patterns evolve material differences could open up between previously similar segments, warranting further fine-tuning of pricing.

88. Building a segmented economic cost view of energy use and utilisation on their network is expected to be a foundational piece of progress that distributors should be demonstrating in their pricing roadmaps.
89. Distributors may wish to consider the merits of differences in locations cost drivers from at least two angles:
    e. Spatial (congestion), where costs differ across a network due to differences in congestion
    f. Spatial (geographic), where costs differ across a network due to differences in customer density, geography or topology.
90. Before engaging in locationally differentiated pricing, the distributor should have regard to the consumer impact of this change and balance this against the efficiency gains of this approach. Avoiding bill shock using an appropriate transition period if the difference is likely to be significant would also be appropriate.
91. If distributors decide not to engage in locational differentiation, they should be transparent about the degree of any cross-subsidisation that is occurring between different locales. Consideration of the appropriateness of locational pricing should be shown in their pricing roadmaps.

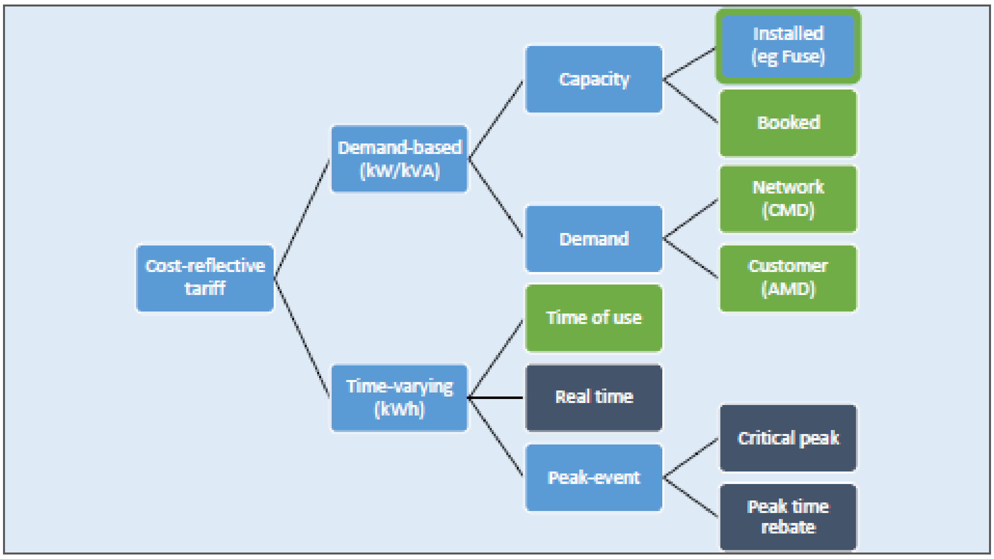
A time dimension to pricing?

92. Distribution networks have traditionally been built to largely allow ongoing consumption during peak periods: aiming to deliver all the energy customers want, when they want it. Whilst ripple control does dampen peak consumption down a little, during a few cold winter evenings per year, for most of the year large parts of New Zealand’s 150,000 km of distribution network are unconstrained.
93. As energy consuming devices have changed and demand for energy has evolved, the peaks have tended to rise to match the habitual patterns of peoples’ daily lives. As demand increases and technology such as EVs become more widespread, we could see more congestion peaks. Higher peaks may drive distributors to build more capacity for a network that for the bulk of the time is underutilised. This could be inefficient – if customers must pay for something that they mostly do not use. Or it could be efficient if customers’ value for the extra energy is high.
94. Where congestion exists, correctly timing price signals to reflect the cost to the network and incentivise people to value their usage will reduce costs for everyone and lift welfare. Two of the most striking examples of habitual consumption that have been proved to be readily influenced are:
    a. load control of hot water heating: New Zealand has a long history of ‘ripple control’ to allow distributors to control hot water heating to reduce evening peaks. A discounted price paid by the customer for giving occasional control to the distributor benefits both, with a barely noticeable life change from the customer, and potentially large investments by the distributor avoided
    b. home charging of EVs: This market is growing quickly and government policies to encourage further take up will exacerbate the potential for people to plug in when they return home. Domestic chargers (not necessarily fast chargers) will add to the evening peak, meaning new capacity is built (or network alternatives introduced), when instead a simple price signal could achieve a shift in charging that avoids the need for new investment.
95. Effectively pricing the time of use of energy to signal when (and where) congestion exists lifts efficiency of network use. However, assigning a time of use price signal to time periods when no congestion is present for example, could send the wrong signal and create a worse outcome than a flat charge. One caveat here is that good price signalling by a distributor takes account of trends that could see congestion arising, and so pre-emptively signalling to customers to become accustomed to a future price structure is prudent and encouraged by the Authority if the future congestion is sufficiently proximate.

96. Without a link between congestion and price signals (current or forecasted), a distributor risks reducing the welfare of customers, encouraging actions (defection, reduced consumption) that it does not desire, distorting behaviour unnecessarily and causing harm to all parties.

97. The ENA's *Guidance on Pricing Reform* helpfully lays out a view of pricing structures in the figure below. It focussed attention on the types of cost-reflective pricing highlighted in green. We have focussed attention on the Time of Use and Peak Event tariffs as these are the most likely structures to be useful in the New Zealand context. This is not to say that they are the only ones, nor that they should be applied without considerable thought to their intricacies, nuances, applicability and actionability.

Figure 2: Price structure options



Source: Electricity Networks Association, Guidance on Pricing Reform 2017 [24]

Time of Use

98. Time-of-Use (TOU) pricing has been the first stepping-stone for many distributors' pricing reforms. The key to using TOU effectively is to understand and signal when in a period – an hour, day, week, month, or season – network congestion is occurring (or expected) and so when the costs to deliver energy are highest, and to lift prices in those periods appropriately. Distributors should consider using TOU pricing where they can demonstrate that there is a need for it, for example a rapidly growing penetration of EVs in a particular area of the network, resulting in actual or imminent congestion.

99. TOU may not necessarily be the end point. Our assessment is that many distributors have implemented TOU as a means to start the journey of pricing reform, but that the next step for them is not clear. Our concern is that TOU can be a blunt and may be an inefficient method of cost reflectivity especially if not matched to actual or impending congestion, and that after implementing TOU, distributors may reduce their focus on pricing reform.

100. We expect distributors to assess the effectiveness of their TOU pricing to determine if there has been a resulting change in retailer and customer behaviour, noting whether:

   a. there has been a load shift of consequence, and

   b. the load shift has met the desired need.

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24 *Guidance on Pricing Reform, ENA, August 2017,* https://www.ena.org.nz/news-and-events/news/final-pricing-guidance-report-published/document/151

101. We accept that TOU has the advantage of being easily understood by customers and so may be a useful step in changing habits or focussing attention. When customers can respond well to TOU structures it allows for existing network capacity to be better utilised and delay or avoid additional capacity investment. However, if the congestion problem that TOU is trying to solve is not well targeted then TOU risks being a change for the sake of making change. This is detrimental to customers' acceptance and risks creating a backlash to reform that distributors will have to bear later when they better target price signals.

102. We are also cognisant that TOU can have an undesirable effect of simply shifting the congestion out, if customers or automatic controls ramp up as the peak period finishes. Determining if this occurs, and if it is important to managing congestion, is a learning experience that would warrant further action.

103. We expect distributors, over the coming year, to understand whether their TOU implementation has reduced network congestion and therefore had the effect of 'cooling' heat maps of utilisation and congestion, and whether this effect can be tied to an Asset Management Plan change that has delayed or avoided future network investment.

Peak event pricing

104. A further evolution of TOU pricing may be to factor in peak events on a network, sub-network or feeder and overlay an additional charge during these times. This will amplify a price signal of an existing TOU structure, and for some networks just a 'critical peak price' may be sufficient to manage time-bound congestion, eg, the coldest winter night in a season, or rural coastal areas with a high density of holiday homes over the December/January holiday season.

105. Research has shown that using critical peak pricing is highly effective in reducing peaks, especially when paired with technologies that automate the management of usage in these times. The size of the peak signal is clearly a significant factor in managing peak reduction, and the infrequency of the number of peaks allows customers to make an 'extraordinary' decision rather than change a 'sticky' consumption habit.

106. Ensuring any peak signal is communicated a reasonable period in advance is considered the most effective way to allow customers to respond and engage with the signal, but there are limitations. Firstly, distributors do not always have access to customer contact data so cannot communicate directly and would be relying on 'links in the chain' to communicate the signal. Secondly, to be effective customers need to be engaged in managing their consumption or have automation in place that allows a response. For a network that sees critical peaks, this form of pricing is a useful method for limiting the near-term impact of demand, and so can delay investment and therefore a critical peak pricing structure may be effective, albeit not wholly cost-reflective.

Controlled load

107. New Zealand distributors are advanced compared to overseas networks in managing the timing of their discretionary network load, mostly through the aforementioned ripple control. Distributors are practiced in managing these devices to reduce peaks, leaving themselves and customers better off, with little impact on their daily lives. The effect of good load management is illustrated by Orion's use of load control in the figure below.

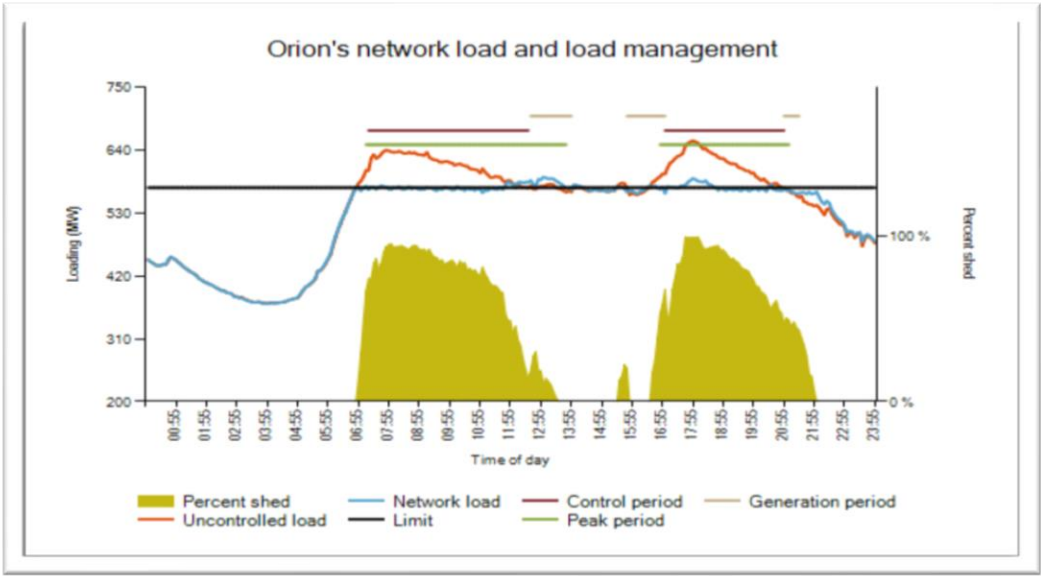
108. Load control for hot water heating is the common application at present and has proven to be effective for managing congestion. Envisioning a future of more widespread EVs, PV and other controllable DER means that there are opportunities for greater use of demand response. Further, flexibility in the load side – including control of hot water and EV charging - will play a key role in future in balancing fluctuations in supply of energy from intermittent renewable generation around the grid.

109. Technology is likely to assist in the load control of EV charger installation, and as it has a similar load profile to hot water, this is an area where we anticipate rapid development and for distributors to

actively encourage uptake, either directly or via pricing structures and signals that support other control devices.

110. We understand that the penetration of traditional ripple control for hot water at new ICPs is reducing in some parts of the country and in the short term this may hamper efforts to control hot water load more broadly. Whether this an economic decision (related to real or perceived value from the installation that could be addressed by more cost-reflective pricing) or there is some other barrier to more widespread uptake is not clear. In time, other communication and dispatch technologies may provide viable alternatives to ripple control.

Figure 3: Load control at Orion



Source: Electricity Networks Association, Guidance on Pricing Reform 2017 [25]

111. We expect to see distributors, retailers, and flexibility traders active in providing the ability to increase options for customers to manage these 'heavy' loads in return for a discounted pricing structure and/or paying a third party for this control. The Authority envisages a future where distribution congestion might be managed, to an extent, by demand flexibility, utilising emerging technology and business models.[26]

Transmission charges

112. Distributors will need to pay attention to the impact of the proposed changes in Transmission Pricing Methodology, and within the bounds of regulation (ie LFC), the Authority expects that for residential and small commercial customers:

   a. fixed transmission charges, which are not intended to influence customers' network use decisions, should be passed through as fixed (daily) distribution charges[27]

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25 *ibid*

26 We acknowledge the work of the Innovation and Participation Advisory Group in the area of efficient demand response: https://www.ea.govt.nz/assets/dms-assets/28/Transpower-DR-programme-review-draft-memo.pdf

27 This would include the proposed benefit-based charges and residual charges, which are intended to be largely a fixed charge.

b. transmission charges that are intended to send price signals that influence network use should be passed through as distribution charges that send the same price signal (and influence network use in the same way) as the transmission charge.[28]

113. The current LFC regulation may not allow the above expectations to be met immediately, however we expect distributors to be forward looking in how their treatment of transmission charges are passed through as regulation change allows.

Recovering the residual

114. As depicted in Figure 1, the final step (step 3) in the price setting process is to ensure that the revenue a distributor collects will match its allowed revenue (ie, the residual revenue). It is rare that the revenue collected from the price signalling step will match the revenue a distributor is allowed to earn. Most of the time the revenue collected from the price signalling part of the process will be less than the allowed revenue, but sometimes it could be more than the allowed revenue (especially if the distributor has a very strong price signal it needs to send to one group).

115. The difference between the revenue earned from the price signalling step of the process and the distributor's maximum allowed revenue is called, for the purpose of this guidance, 'the residual'. A share of this residual is allocated to each customer group. The price signal, plus the share of the residual, makes up a customer's distribution charge.

116. Because this residual amount has no need to send a price signal to any one group (because all the price signalling work is done in the first step) this residual recovery process should be done in a way that means a customer has no reason to change their electricity consumption use or pattern. This is what is meant by 'non-distorting'. To be non-distorting, the residual should be unavoidable, meaning that customers should not be able to take an action that means they avoid paying all or part of the charge (other than disconnecting from the network).

117. There are many ways that a distributor could allocate the residual across customers within a customer group, ranging from a simple per-ICP basis, to proportionately allocating the residual referencing a metric that reflects the size of that customer, and so it's overall effect on the network. For example, an allocation based on maximum demand could reflect the relative size of each customer's maximum usage of the network. Any metric referencing size or use would ideally be a historical reading of the metric, as this would create fewer possibilities for avoidance, making it a less distortionary allocator. As is the case for the other aspects of price setting, there is no one-size-fits-all solution, as differing methods can produce different outcomes that may be best applied by one distributor, but different for another.

118. In the 2020 Transmission Pricing Methodology guidelines the Authority decided that the residual portion of the transmission charge should be allocated using a customers' historical anytime maximum demand. Historical data is used because this is less distortionary than using more recent data, and the anytime maximum demand is a simple way of most likely reflecting a customer's size (as a proxy for their ability to pay). (However, residual cost allocation should never be updated regularly based on a customer's anytime maximum demand *in each period*. That would create a strong inefficient price signal and seriously distort consumer demand.)

119. In determining which is the least distortionary method for each distributor, we expect that distributors will balance the desire for simplicity with the outcomes produced by the different allocation methods. If the financial impact on customers from two methods is insignificant, then we expect that the simplest calculation method will be selected; however, we acknowledge that other methodologies fulfil other objectives, such as representing the relative use of the network and this may be appropriate. As with all pricing changes, considering impacts on consumers will be important.

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[28] An example could be a transitional congestion charge (TCC). The current proposed TPM does not include a TCC; however, the TPM guidelines provide for a TCC in certain circumstances, and Transpower might propose to introduce one in future.

Part 4: What a good pricing evolution will look like

This Part aims to provide guidance on how pricing responds to the changing needs of a network, the pricing response options that align and why they are needed.

120. We have considered stylised hypothetical networks that illustrate the way that we believe good pricing reform should be conceived and implemented.
121. These stylised hypothetical networks are conceived of in a world where the LFC regime does not exist, and the Authority acknowledges that they are aspirational at this stage; however they provide a good guide for distributors developing plans for an end target following steady reform over the years ahead.
122. The networks derived are based on two defining characteristics:
    a. density – urban and rural
    b. geography – remote and non-remote (applies more commonly to the Rural network examples).
123. In considering these networks we are focussed on residential and small commercial ICPs only. This simplifying assumption is reasonable as:
    a. Residential ICPs comprise 85% of total national ICPs which predominantly affects the length and density of distribution networks
    b. Commercial and Industrial ICPs are typically subject to non-standard individual contract negotiation that already, as we understand it, largely aligns with cost-reflective pricing principles
    c. Medium sized commercial ICPs are typically subject to load/demand pricing.
124. We have proposed simplified examples of the types of networks, the changes they face in growth, demand for energy, and access to the network, and the resulting ‘best practice’ pricing structures.
125. In some situations we have offered a near-term view as well as a longer-term view on best practice.
126. We have used a shorthand for describing the state of congestion on the network*, Design* compared with *Demand:*
    a. where a network is currently meeting the requirements of customers at their peak demand we describe it as Design = Demand. Such a network, in whatever configuration as it currently is in, is supplying connected customers with their electricity needs and faces no congestion
    b. where a network faces congestion at times we describe it as Design < Demand. Such a network is currently insufficient to meet customers’ demands at times of peak demand
    c. where a network has significant spare capacity at times of peak demand, we describe it as Design > Demand.

How Capital Contribution policies apply

An important element in the forward view of a network's expansion from the growth of ICPs and new load/demand is how a distributor's Capital Contribution policy (otherwise known as Customer Contribution, Customer Connection etc) applies.

This is important as growth within the existing network and expansion of the networks is funded by both new customers and the existing customers (ie via the distributor's revenue recovery). The amounts that distributors invest are recovered by way of pricing (line revenue) in accordance with the size of the capital they have invested (RAB as defined in the Commerce Commission IMs). Amounts funded by customers/new connections are outside RAB, and no revenue applies to them, ie, they should have no bearing on pricing to the wider network.

While substantial differences exist between distributors' approaches to their policies and methodologies, and the amounts they require from customer-initiated works **they mostly attempt to charge new connections in a manner that does not impose additional costs on existing customers that do not benefit from the new connection.**

It is not within the scope of this Practice Note to consider the efficacy of the contribution policies and methodologies, but it is clearly signalled that some consideration should be undertaken to ensure that the economic costs of the connection/load growth are adequately and efficiently recovered and do not burden the wider customer base.

The Authority expects to issue further guidance on cost allocation relating to new and expanded connections in the future. In the meantime, certain distributors have sought clarity on a connection/capital contribution issue regarding distributed generation. Specifically, they have asked how the incremental cost pricing principle for connecting distributed generation to distribution networks, in Schedule 6.4 to the Code, impacts on the recovery of the costs of building anticipatory capacity into these connections.

The incremental cost pricing principle applies equally to first, second and subsequent mover DG connecting at any point on a distribution network, capping the capital contributions that can be sought from them. In terms of any anticipatory capacity built that anticipates DG connecting as a second or subsequent mover, the Authority considers that the best interpretation of Schedule 6.4 to the Code is that it allows distributors to seek capital contributions from all subsequently connecting DG (expanding first mover; second and subsequent movers). This is consistent with Schedule 6.4 to the Code (clauses 2(i)-(m)) and the Authority's 2019 distribution pricing principles.

"Anticipatory capacity" refers to the extra capacity built into connection assets over and above what the initial connecting party (the first mover) needs. The anticipatory capacity is being built for future, uncertain, customers. Building this extra capacity now is efficient if it is likely that further parties will connect to the distribution network at the same connection point, as building one bigger asset now is usually cheaper than building two smaller assets that add up to the same capacity - one now, one later.

Recovering the costs of anticipatory capacity can lead to what is known as type 2 first mover disadvantage: where the first mover must carry the full cost of connection capacity in excess of its own requirements, until subsequent movers connect. This creates uncertainty and cost for the first mover that may discourage it from connecting/lead to delays in otherwise efficient investments, eg, could lead to businesses slowing down their electrification, or to generation investment being delayed.

127. The key distinction with this shorthand is that it describes the time of the day, week, or year where a network faces its peak demand, rather than an assessment of the all-year around demand requirements. It does not reference reliability or resilience standards, as these factors are part of a

distributor's asset management planning that are considered as part of the Commerce Commission's Part 4 regulation.[29]

128. The examples start with the 'What it looks like now' and then builds future scenarios from that base. This approach illustrates the way we believe that pricing should respond dynamically to changes in the network's use and demand and reflects the iterative way that we believe good pricing practice evolves.

129. The pricing structure in the starting position of 'What it looks like now' is currently an aspiration for many distributors as it has a 100% fixed daily charge. This is a strong indication from the Authority of an efficient pricing signal, albeit one in which no network with a LFC customer grouping can currently achieve, but we expect that distributors who match these network conditions will reform towards as regulation allows.

Urban network

What it hypothetically looks like now

130. Design matches or exceeds Demand, with no indicators of congestion. Prices for services assist with Design = Demand such as load control (hot water ripple control) and 'first off' pricing options, and these are currently used in the congestion management of the network.

131. Network investment is predominantly historical, with renewal and growth expenditures within current and Asset Management Plan expenditure allowances.

132. Future investment is predominantly replacement capex, with any increased functionality planned to be uniformly installed. Where future service offerings do eventually differ, the allocation methodology would apportion costs appropriately.

133. **Pricing rationale:** No requirement to signal a change in customer behaviour, so pricing should recover the invested capital and ongoing maintenance of the existing network. With no capacity issues there is no reason to signal a price that influences consumption, therefore there is no rationale for a variable charge.

134. Controlled load manages congestion and avoids further investment, so can be zero-rated (ie $0) for distribution pricing at peak, which should also aid customer uptake.

135. **Pricing:** Fixed daily charge

Network change scenarios

136. Using the above conditions for our hypothetical network as the starting point, we consider seven factors that may impact use of the network, and how we see pricing respond. Each scenario is expanded upon over the following pages.[30]

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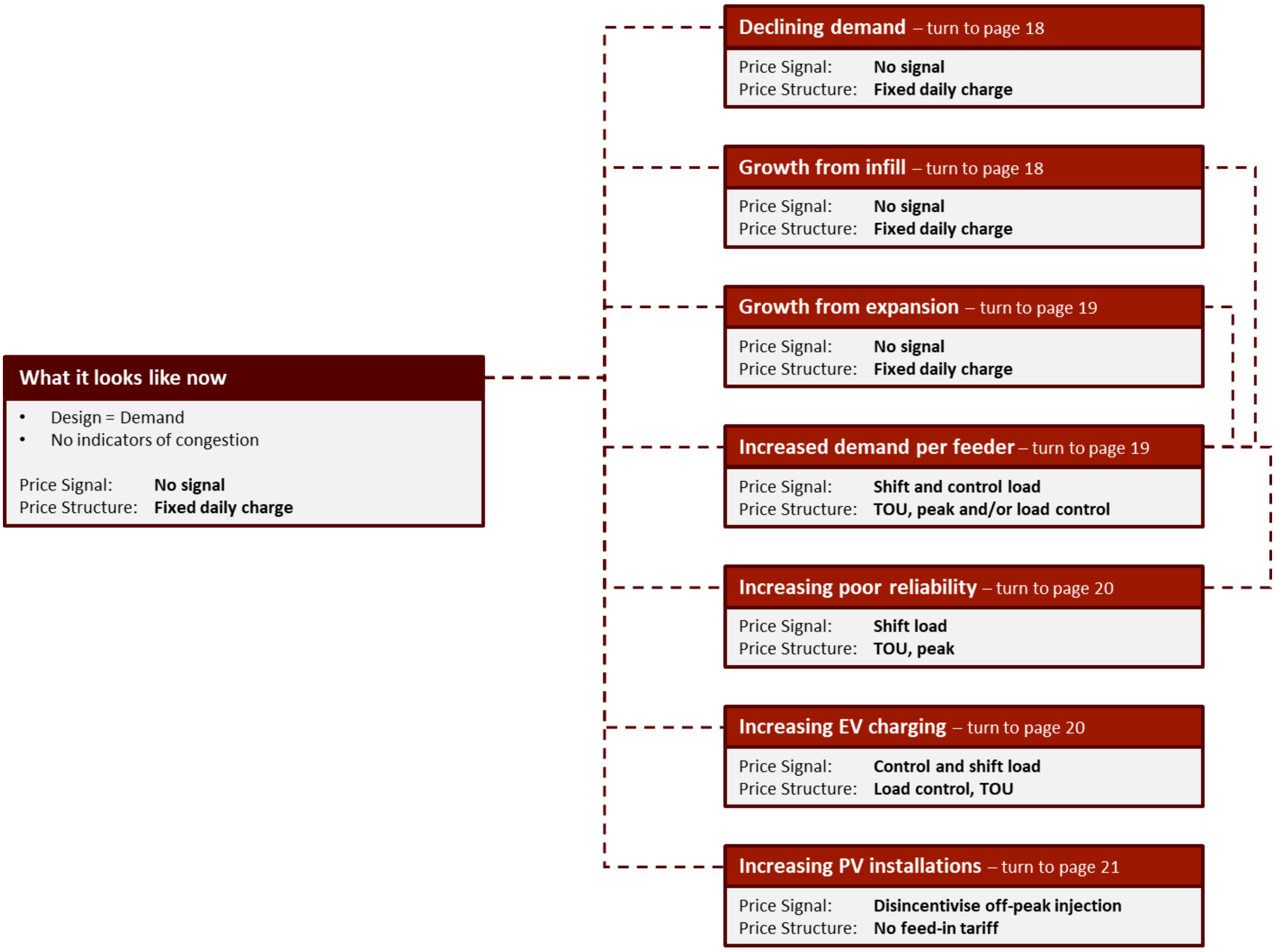
[29] Investment undertaken to improve reliability, resilience or growth would be form part of the total revenue a distributor can recover, and so would form part of the allocation of costs exercise, but for this set of simplified examples they are separate to the price signalling discussion

[30] References to a peak charge or TOU pricing mean such a price signal that is required due to imminent network congestion.

Figure 4: Urban network scenarios map



Declining demand

137. The network is not constrained, spare capacity is increasing, therefore Design > Demand.

138. Opex & maintenance costs fixed with total line revenue unchanged (ie, derived from existing and replacement capex).

139. **Pricing rationale:** Design exceeds Demand. There is no capacity constraint signal needed, nor any need to change total usage or time shift usage.

140. **Pricing signal:** No change - Fixed daily charge

Growth from infill

141. Identified by an increased ICP count on feeder leading to increased total network demand.

142. Design <= Demand – ie, congestion may become evident or predicted on impacted feeders and there may be a short-term incentive to reduce the peak.

143. Longer term, where an investment upgrade may be necessary, the network's Capital Contribution policy should apply to reflect the incremental impact on network costs.

144. Depending on the specifics of the contribution policy relating to new connections there may be costs associated with increased investment on the feeder to be shared.

145. **Pricing rationale:** Upgrades to a feeder may be fully recovered by the contribution policy, to balance Design = Demand. Where this occurs there is no need to signal a change in consumer behaviour across the network/feeder.

146. **Pricing signal:** No change – Fixed Daily Charge.

147. **Near-term pricing rationale:** Before an upgrade to a feeder can be completed, or if the upgrade investment is not sufficiently recovered through the contribution policy, there is an incentive to signal congestion to shift load in order to balance Design = Demand and delay or avoid investment.

148. **Pricing signal:** See 'Increased demand per feeder'.

Growth from expansion of the network

149. Identified by a new feeder or extension of an existing feeder.

150. The contribution policy recovers some or all of the network investment for the new development.

151. Upgrades before new expansion are not always recovered.

152. **Pricing rationale:** Additions to the network may be fully recovered by the contribution policy, to balance Design = Demand. Additional capex is (theoretically) recovered by the addition of new billing volumes. Where this occurs there is no need to signal a change in consumer behaviour across the network/feeder, pricing should merely recover the invested capital.

153. **Pricing signal:** No change – Fixed daily charge.

154. **Near-term pricing rationale:** Before an extension of a feeder can be completed, or if the upgrade investment is not sufficiently recovered through the contribution policy, there is an incentive to signal congestion to shift load in order to balance Design = Demand.

155. **Pricing signal:** See 'Increased demand per feeder'.

Increased demand per feeder/GXP

156. Increased demand could be for many reasons across different feeders, due to the source of the increased load, such as:

    a. Changing household energy use. This could include EV connections (see also section below on EVs).

    b. Historical infill or expansion of a feeder occurred but did not trigger an upgrade at the time.

157. Land use changes can also alter demand on a feeder - for example, a fringe rural area that has seen increased density to become more urban in density – ie, urban sprawl.

158. Feeder level heat maps (or a similar alternative) should be the reference for identifying the areas needing attention and for determining the target of sharper price signals and measuring the success of them.

159. Smart meter data may be required to better identify source, location, and timing of increased demand.

160. Monitoring of the load and changes will be required to determine whether the pricing response has been appropriate, and also if it is continuing to trend up and requires more action.

161. **Pricing rationale:** Design < Demand. Load shifting should be incentivised to avoid/delay capex. This comes in addition to existing load control measures. If demand holds up then it indicates capex may be appropriate.

162. Capex invested should be recovered from the affected feeder with the forward view of the investment and its price impact being part of customer engagement to provide fully informed decisions.

163. **Pricing signal (1):** Where congestion is regularly peaking one or two times a day – TOU. Vigilance will be required to ensure load shifting has not simply extended peak periods.

164. **Pricing signal (2):** Where congestion is peaking to critical levels during a season (such as over winter evening peaks), an enhanced seasonal component may be necessary to amplify the impact, ie TOU + Seasonal peak charge. This may involve a reduced off-season structure to stress the impact of the peak season pricing.

165. **Pricing signal (3):** Load control pricing may be strengthened to further incentivise controllability of load, ie EVs and hot water. This should be utilised in conjunction with TOU signals.

166. **Longer-term pricing signal:** TOU is a useful initial step for customers to get used to signals. Where congestion is managed as part of a short period within a year (say a few cold winter nights) transition to a further enhanced peak signal, either stand-alone or as part of a TOU structure.

Increasing poor reliability/security of supply

167. Worst performing feeders are identified through a distributor's asset management planning process. The focus here is on feeders that are not seeing an increase in per-ICP demand, but rather diminishing performance with a stable load.

168. Opex may be the least cost remedy for some time and the only option for a period if capex is a multi-year exercise. Pricing can assist in relieving pressure on the assets for a time.

169. **Pricing rationale:** A pricing response is appropriate to assist managing load to temporarily assist reliability (within the scope of the regular pricing adjustment timeframes). The pricing rationale is likely to be similar to the above scenario, but for a shorter period and potentially more targeted and involve specific customer engagement to address and improve the pricing signal's impact.

170. **Pricing signal (1):** Where congestion is peaking during one or two times a day – TOU. Vigilance will be required to ensure load shifting has not simply extended peak periods

171. **Pricing signal (2):** Where congestion is peaking to critical levels during a season (such as over winter evening peaks), an enhanced seasonal component may be necessary to amplify the impact, ie TOU + Seasonal peak charge. This may involve a reduced off-season structure to stress the impact of the peak season pricing.

Increasing EV charging

172. Installation of EV chargers can be at any point of a network, and experience thus far suggests it is not an urban-only phenomenon.

173. Increasing load during peaks is the main concern for all distributors, but as EVs are still a fairly new technology there is an opportunity to tune customer expectations early with an appropriate signal.

174. Unless a distributor has systems in place to 'mark' new installations of standard or fast chargers that then necessitate customer line upgrades, and can match it to the ICP for metering, there is no visibility of the load that links it to a charger.

175. Controlling the load has marked benefits for distributors to manage existing networks and avoid increased investment.

176. Whether the load is controlled or not, having a signal that shifts the loads is desirable.

177. **Pricing rationale:** EV charging is sudden and burdensome and experience thus far shows it typically coincides with existing peaks. It is however, a very controllable load and as technology evolves, it will

be increasingly 'shiftable'. Controlling the load in a manner similar to hot water heating is feasible and desirable at this stage.

178. **Pricing signal (1):** Load controlled, possibly with a distributor, retailer or flexibility trader provided smart charger if the cost can be justified to avoid other network upgrade costs.
179. **Pricing signal (2):** TOU where congestion trends suggest demand can be shifted to low demand times – vigilance will be required to ensure load shifting has not simply extended peak periods.
180. **Pricing signal (3):** Where a feeder upgrade is necessary, costs should be allocated to the feeder through an increase in fixed daily charges.

PV installation

181. PV installations on uncongested daytime networks provide no benefit to the distributor.
182. Where network prices using a significant portion on a variable charge PV can distort economic signals by reducing consumption (and therefore cost recovery) but does not reduce the ICP's reliance on the existing network.

183. **Pricing rationale:** With no daytime congestion evident, there should be no reward provided to PV installations for feeding into the distribution network.
184. **Pricing signal:** No feed-in tariff to reduce distribution charges – rely on fixed charges to send the appropriate network use signal.

PV installation with storage/other DER

185. If an installation is willing to inject when the distribution network requires it, then it is reasonable that a discount/feed-in tariff can be provided.
186. Having control of the injection is not currently common and so setting the price efficiently is difficult. This may change in the coming years, and distributors will need to be aware of developments to support this.

187. **Pricing rationale:** Distributors should err on the side of caution with DER pricing, and be sure that location aspects are well understood before setting prices. It is more likely that DER pricing will need more frequent updating than the current annual process, and this uncertainty is important to sending the correct efficient price signal.
188. **Pricing signal:** Distributors should exercise caution with sending pricing signals in the near-term to ensure they understand the impact on their network costs.

Rural networks

What it looks like now

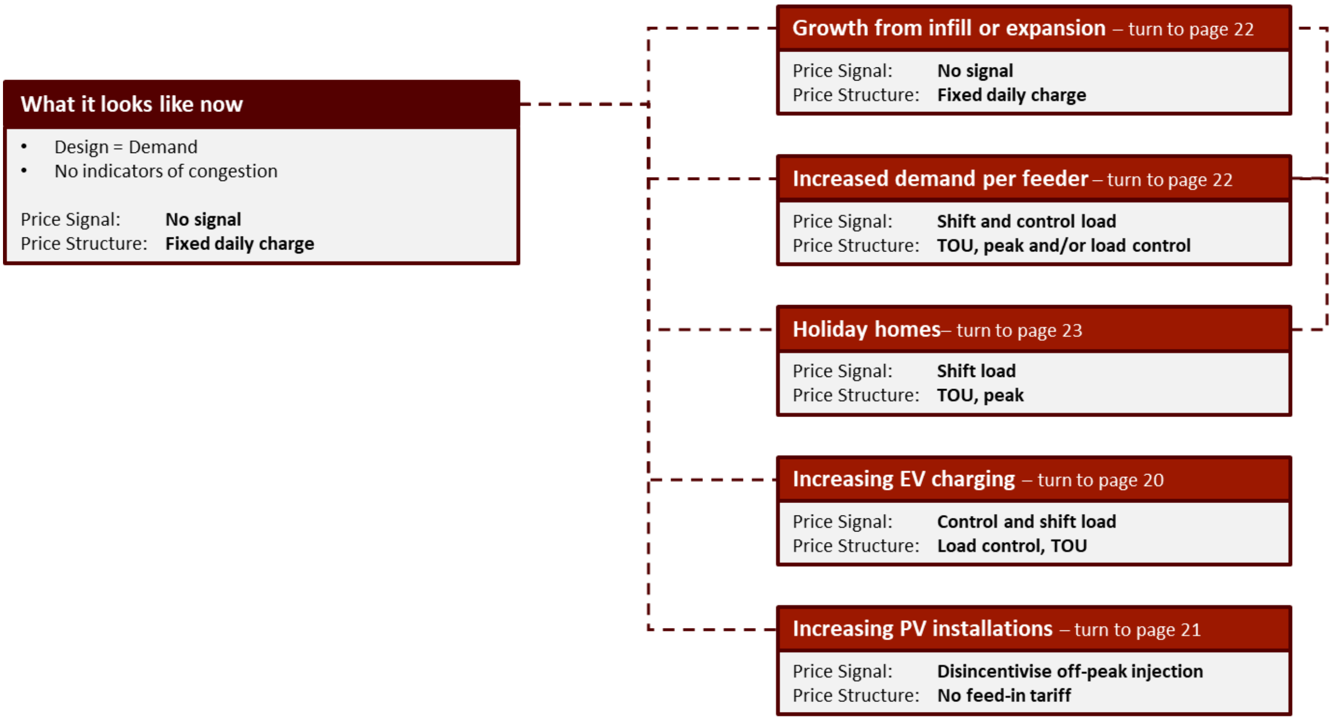
189. Rural residential and small commercial connections often have slightly different usage patterns than similar urban customers but are largely the same in how they interact with the network.
190. More likely to have reliability or resilience issues – mostly related to weather and asset-lifecycle issues.
191. Network investment is predominantly historical, but land use changes need to be watched for as changes often lead to different energy usage and demand patterns. This can lead to pockets of congestion.
192. Future investment is often replacement and resilience capex, with increased functionality a lesser priority than building in improved reliability.
193. For a network that also has a denser urban centre, there should be customer grouping in place that reflects that rural cost of supply/losses are greater than an urban network.
194. Cost of supply modelling for a rural network is likely needing to be more segmented than with an urban network to understand differences in costs and energy losses. This factor tends to make rural networks strong candidates for many non-network energy alternatives. Therefore, a distributor must be more conscious of the cross-subsidisation decisions they make in order to not disrupt technology competition.

195. **Pricing rationale:** Rural residential and small commercial connections often have slightly different usage patterns than similar urban customers but are largely the same in how they interact with the network.
196. **Pricing:** Fixed daily charge. Rate should reflect the true cost of supply and therefore expose engineering design to good options analysis for non-network alternatives.

Network change scenarios

197. Rural networks have some features that set them apart from urban networks for pricing purposes and the signals that may need to be sent, and we have depicted them in the following pages. The influence of EVs and PV however, are the same as above.

Figure 5: Rural network scenarios map



Growth from infill or expansion of network

198. Largely the same as an urban network, with some distinctive features that may affect pricing.

199. Often infill growth is slower than on urban networks and therefore less likely that the incremental ICP growth will stress the existing network design (assuming it is currently matched).

200. Extensions of rural networks are typically not fully recovered from the beneficiary/exacerbator as the economic costs are significant.

201. Increasing density of rural networks is likely to reduce costs to serve, and so benefit the existing customer base, and this may affect the cost of supply modelling.

202. **Pricing rationale:** Pricing signal is the same as for an urban network.

Increased Demand per feeder/GXP

203. Land use changes are the dominant reason for substantial changes in energy demand and it is this which makes the most likely response in a rural network different from an urban network.

204. It is usual that there is even less visibility of the LV network in rural areas than in urban networks, but there is often a greater ability to 'eyeball' the reasons for changes in capacity and demand, so a distributor can usually fairly accurately target the capacity change costs to the source.

205. **Pricing rationale:** Design < Demand. Load shifting should be incentivised to avoid/delay capex. This comes in addition to existing load control measures. If demand holds up then it indicates capex may

be appropriate. A move to capacity charging may best align with the cause of the increased demand, and better send the needed cost-reflective price signal.

206. **Pricing signal (1):** Where congestion is peaking one or two times a day – TOU.

207. **Pricing signal (2):** Where congestion is peaking to critical levels during a season (such as over winter evening peaks), an enhanced seasonal component may be necessary to amplify the impact, ie TOU + Seasonal peak charge. This may involve a reduced off-season structure to stress the impact of the peak season pricing.

208. **Pricing signal (3):** Load control pricing may be strengthened to further incentivise controllability of load, ie EVs and hot water. This should be utilised in conjunction with TOU signals.

209. **Longer-term pricing signal:** TOU is a useful initial step for customers to get used to signals. Where congestion is managed apart from a short period within a year (say a few cold winter nights) transition to a further enhanced peak signal, either stand-alone or as part of a TOU structure.

210. For some networks it may be appropriate for a move to a full demand charge. A demand charge structure would, based on experience, be most useful if the occasional peaks can be predicted and communicated to customers.

Increasing poor reliability/security of supply – holiday parts of the network

211. Peaks on networks may occur for only a few days in a year, with little elasticity of demand – eg long weekends and holiday periods in certain parts of the country.

212. Because the increase in demand in these areas is for such a short period it often doesn't meet the upgrade standards for many distributors (usually based on normally resident population, economic activity, quality of supply measures etc).

213. The costs to upgrade these areas come under scrutiny in certain times of the year, and often have a vocal customer base for a short period. A distributor's decision is always about where to apply its resources best.

214. Upgrade costs related to these parts of networks should be borne by these areas.

215. **Pricing rationale:** Design < demand – often only for a short period. The economic costs to lift supply security cannot be recovered through variable charges, given the often small volumes delivered.

216. **Pricing signal (1a):** Peaks are usually easily predicted but customers tend to have limited discretion/desire to manage load. A Network Peak Demand would best reflect the costs and usage but will likely create a very large spike to monthly billing.

217. **Pricing signal (1b):** Increase in Fixed Daily Charge.

Part 5: Expectations on the timing of reform

This Part aims to make clear what the Authority expects of distributors in the coming years, as they accelerate the reform of pricing.

The next two years, to 2023

218. The Roadmaps developed by distributors have been valuable for us to understand progress being planned by each distributor, and useful as a tool for distributors to hold themselves to account to customers, Boards, and regulators. The first steps for all distributors was to develop deeper understanding of what the pricing principles meant and how they should be applied. **We expect that this work is comprehensive and complete, then updated annually.**

219. The most recent steps that many distributors have taken has been to apply the principles to understand their own network needs for aligning prices to a cost-reflective structure. This should have included building knowledge of the varying economic costs across the network and understanding locations, timing, and sources of congestion. Discovering the nature of the congestion and how price signals can address it should be well under way. **We expect that after the past three years that enough of this work has been done to take substantive action now.**

220. Examination of pricing reform options revealed that under the LFC regime there was, at least across some pricing dimensions, limited ability for distributors to have a proportionate outcome change from the work required to implement pricing changes. However, reform in the interim is still possible, and LFC does not create a barrier to actioning critical preparatory steps such as better understanding network flows relative to capacity. The Government's announcement of a five-year phase out of LFCs allows distributors to accelerate their implementation of reforms. Our understanding is that the modelling and trials work undertaken now would allow distributors to 'press the button' as LFC is being phased out. We would be disappointed if distributors decided to delay further progressing their reform work until after the LFC is fully removed, as this could waste up to five years in their reform process. **We therefore expect to see distributors have clarity on their optimal process and at a minimum undertake the first steps from the April 2022 pricing year, with this to be reflected in progress up the scorecards.**

221. Changes to pricing methodologies may appear to be slow, when undertaken annually, but ongoing customer engagement work and trials and modelling to finely tune the next steps in development can, and should, continue throughout the year.

222. We acknowledge that even in trials undertaken now LFC may have an influence, but we do not see this as an impediment to proceeding with them.

As the LFC is being phased out from 2022-2027

223. During the LFC's phase-out we expect the first major tranches of pricing reforms to have been progressed. This will involve increasing the effectiveness of pricing signals and where appropriate will see improved cost allocation outcomes, increasing fixed charges as a proportion of pricing structures, and/or review of the responsiveness and customer engagement from the initial steps of pricing signals being used to address congestion. **More detailed expectations will be developed within the engagement framework referred to in Part 1: Forward engagement focus**

224. We expect a robust feedback loop to aid continued advancement of reforms, in a manner that directly informs ongoing changes. This will include continued updating of network understanding and aligning pricing with network requirements, as well as increased customer engagement that helps distributors to align their pricing intentions with realised outcomes.

225. We note that the Government has agreed that there should be a review on the progress of the LFC phase out in late 2023, and this will provide the Authority, industry and wider stakeholders an opportunity to assess pricing reform progress and customer impacts.

226. We would like to see distributors have a link between the scorecards and their roadmaps. We would like to see distributors have their own expectations on how the work they do in delivering their roadmaps and pricing reform will change their future scorecard ratings, as a way for distributors to hold themselves to account for their commitments and roadmap plans.

Appendix A Glossary

Authority means the Electricity Authority, being the Crown entity established under section 12 of the Electricity Industry Act 2010 to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers

Avoidable costs are those costs that can be avoided by not serving a customer or customer group. Examples of avoidable costs include billing and customer service costs, connection costs specific to the customer or customer group, and additional maintenance costs

Consumer groups means for pricing purposes, consumers grouped to have similar characteristics, similar network costs, and similar consumption profiles. Consumers within a group are typically subject to the same pricing plan

Customer means a person who has entered into a contract with a retailer for the supply of electricity, other than for resupply, and/or the provision of distribution services, where the electricity supplied to the customer's premises is used fully or partly for domestic uses

DER means distributed energy resources and refers to resources on the network that do not connect to the transmission grid, such as solar PV, energy storage systems and demand response

Distribution services mean the conveyance of electricity on lines, as defined in the Electricity Industry Act 2010, by a distributor

Distributor has the meaning given to it in section 5 of the Electricity Industry Act 2010.

Economic costs are costs of providing the service, and any additional costs (externalities) borne by others (but not the producer)

ENA means the Electricity Networks Association

ERANZ means the Electricity Retailers Association of New Zealand

EV means an electric vehicle, both hybrid and fully electric, and has a battery which has the ability to be recharged from the distributor's network

Fixed costs are invariant to the level of output, eg costs that are invariant to the amount of electricity sent down a network

ICP Installation control point – a point of connection at which the electrical installation for a retailer's customer is connected to a network

Locational marginal pricing is pricing at different locations in the network, reflecting local demand and capacity, and the cost of getting electricity to a particular location

Low Fixed Charge means the Electricity (Low Fixed Charge Tariff Options for Domestic Consumers) Regulations 2004 (LFC regulations)

Marginal cost is the additional cost of producing one extra unit. In the context of distribution, typically the additional cost of serving one additional customer to the network, or the additional cost of increasing network capacity

Non-network alternatives are alternatives to investments in transmission and distribution, often to manage capacity constraints. Examples include demand management, interruptible demand, distributed generation, batteries, etc.

Non-distorting is an action or price is non-distortionary if it does not change the behaviour of consumers or producers

PV means Photo voltaic, or solar panels

Residual revenue / residual cost is revenue that augments the revenue obtained from cost reflective pricing to ensure that fixed costs can be covered, so that firms do not make a loss. (Residual costs for consumers = residual revenue recovered by distributors.)

Retailer has the meaning given to it in section 5 of the Electricity Industry Act 2010

Revenue targets are the levels of revenue that distributors aim or are permitted to obtain, eg as determined by price-quality paths set by the Commerce Commission (where applicable)

Ripple control is demand management of consumer power consumption based on remote control of hot water cylinders

Standalone costs are the costs needed to replicate or bypass a network entirely. If electricity prices are greater than a consumer's standalone cost then the consumer is better off by disconnecting from the electricity network and, for example, generating their own electricity or sourcing it elsewhere

Subsidy-free prices are subsidy-free if they fall below standalone cost but are above incremental cost. A consumer paying a subsidy-free price makes some contribution to a distributor's fixed cost

Appendix B Distribution Pricing: Practice Note August 2019

This refreshed 2021 Distribution Pricing: Practice Note (draft for consultation) itself appends the *Distribution Pricing: Practice Note August 2019* – because the 2019 document's substantive advice on interpreting the distribution pricing principles remains relevant.

The one place where this 2nd edition Practice Note overwrites the 2019 edition is Figure 1, included at page 5 of this document. We believe this updated diagram better portrays the methodology than the figure in the 2019 edition.

ELECTRICITY AUTHORITY
TE MANA HIKO

Distribution Pricing: Practice Note

August 2019

Date prepared: 25 July 2019

1 Purpose of the Practice Note

1.1 The Authority has developed a Practice Note to assist distributors with the consistent, practical interpretation and application of the Distribution Pricing Principles.

1.2 The Practice Note will be updated from time-to-time to ensure it reflects evolving, leading practice, and to address matters raised by the sector and our monitoring activities.

1.3 We welcome feedback on this note from distributors and other parties.

2010 guidelines withdrawn and superseded

1.4 As noted in the June 2019 decision paper that introduced the pricing principles, the Authority withdrew the 2010 Distribution Pricing Principles and Information Disclosure Guidelines prepared by the Electricity Commission. Those guidelines are no longer needed given the Commerce Commission's detailed disclosure rules.

Outline of Practice Note

1.5 In the following sections this Practice Note provides:

- the pricing principles and an overview of the price setting methodology
- guidance on the application of pricing principles
- notes on the subsidy-free test
- considerations in selecting consumer groups
- links between price-efficiency and pricing types
- concluding remarks, and a glossary of terms.

2 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.

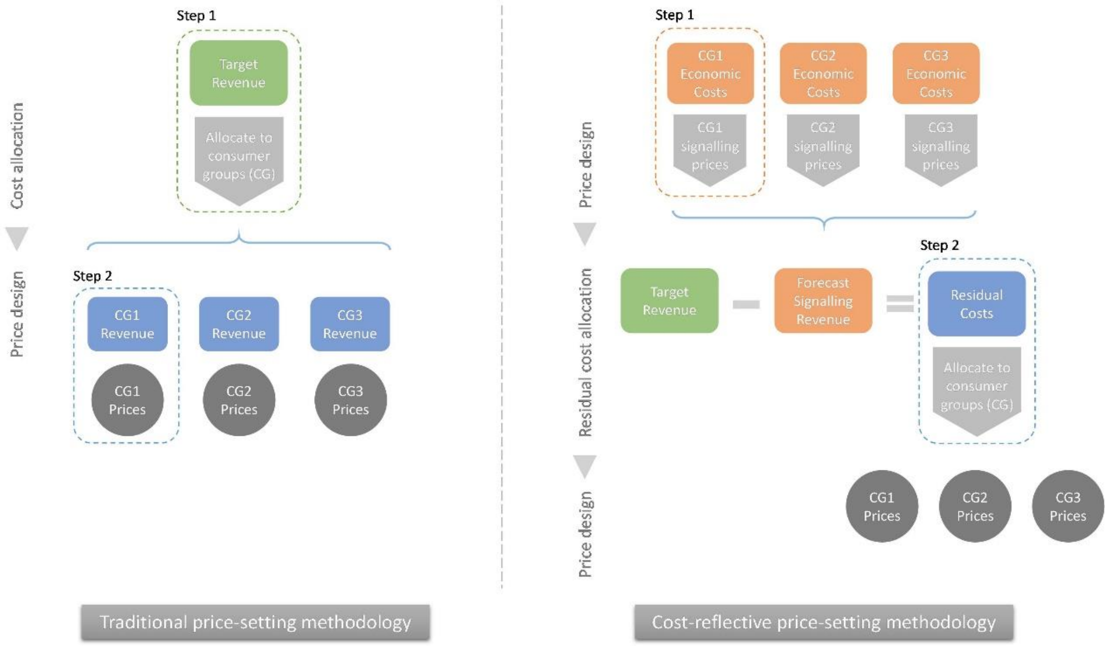
(b) Where prices that signal economic costs would under-recover target revenues, the shortfall should be made up by prices that least distort network use.

(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.

3 Price-setting methodology

3.1 Traditional price-setting uses a process of allocating target revenue to consumer groups, then developing prices for each consumer group. Cost-reflective price-setting operates differently, starting with a process of developing economic cost-signalling prices before considering target revenue in order to identify and allocate residual costs (Figure 1).

Figure 1: Price-setting methodologies



Guidance on the application of the Principles

3.2 The following table provides specific guidance about each of these principles.

Table 1: Guidance on principles

Principle	Guidance
(a) Prices are to signal the economic costs of service provision …	

Principle	Guidance
(a)(i) being subsidy free …	Forecast total revenue for a consumer or consumer group should fall between standalone and avoidable costs. To provide meaningful input to price-setting, this principle is best assessed at a consumer group level. In this form, the subsidy-free test helps guide allocation of residual revenue – ie, revenue (if any) in excess of that forecast to be recovered through cost-signalling price components. The test can also help guide the definition of consumer groups – eg, it may sometimes be necessary to target price signals to more tightly defined consumer groups to avoid exceeding standalone cost.
(a)(ii) reflect impacts of network use on economic costs	Prices should be used to signal economic cost as far as is feasible. Considerations include: - materiality of the cost - ability to estimate the cost - ability to signal the cost - ability of downstream participants to respond to price signals. In the near-term these considerations may favour continued focus on long-term investment costs. Over time it should become more feasible to consider other cost types, such as the costs borne by other parties as a result of network use (eg voltage problems). Pricing considerations include: - which types of costs to signal - how granular any time- and location-specific price signalling needs to be. The scope for increased granularity is likely to increase in future. For example, locational marginal pricing in the distribution network down to ICP level is clearly impractical at the moment, but may become possible as computational techniques and computing hardware improve. Changes in what is feasible and beneficial are why distribution pricing reform is best seen as an ongoing improvement process, not a one-off exercise.

Principle	Guidance
(a)(iii) reflect differences in network service	The principles have been broadened from a focus on service capacity to encompass any differences in the network service provided by or to a distributor. Connection capacity is the most common service differentiator, though differences in firmness of supply are also reasonably common, for example: ▫ some customers have ripple-controllable demand, and ▫ other customers agree to be 'first off' if the network is congested. There are many other ways in which differences in service could be conceived. The differences in the cost of supplying those services should be reflected in prices.
(a)(iv) encourage efficient network alternatives	Network alternatives are measures that provide a (potentially lower-cost) alternative to investing in transmission or distribution networks directly. Examples can include: ▫ demand response ▫ interruptible demand ▫ distributed generation ▫ distributed storage. These alternatives are sometimes, but not always, more efficient than traditional network investment. Distribution prices influence the viability and profitability of network alternatives. In turn, these alternatives may affect transmission investment (eg, in new grid connection assets). Signals conveyed through posted prices sit alongside other initiatives, such as direct procurement, aimed at sourcing network alternatives to avoid more costly traditional network investment.

Principle	Guidance
(b) … shortfall should be made up …	Revenues need to be sufficient to pay for the provision of the distribution network. The revenue from cost-reflective pricing may need to be augmented to make up any shortfall relative to the revenue target. This is because the target revenue relates to current and historic expenditure, while economic costs can include: - marginal cost of supply – for example, long-run marginal cost relates to potential future costs of expanding capacity - costs that need to be signalled, but are not borne by distributors (such as losses or curtailment). As such, revenue from prices designed to signal economic costs can be higher or lower than a distributor's target revenue. Under-recovery of revenue is reasonably likely with prices designed to signal economic costs. In this case, residual costs can be met by dialling prices up or by adding new price components that do not distort the intended economic cost signals (see below). Although less likely, over-recovery could potentially occur. Over-recovery may be resolved with more targeted consumer groups or simply by dialling down price signals.
…with prices that least distort network use.	In contrast to cost-signalling price components, the intention with residual costs is to make up target revenue without influencing behaviour. In principle, it is efficient to allocate higher costs to consumer groups less likely to alter their consumption than those that are responsive. In practice, responsiveness may not be known (or may vary considerably within a consumer group). However, this insight can still provide some guidance when considering: - the quantum of residual costs to allocate to each consumer group, and - the types of price components to use, eg, a fixed charge ($ per day).

Principle	Guidance
(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to…	Distributors should have processes that allow end users to negotiate a departure from standard prices.
(c)(i) reflect the economic value of services	This principle supports end users negotiating a lower price where they would otherwise inefficiently curtail demand (or disconnect or not connect in the first place) if faced with standard prices. This principle is often given effect through a prudent discount policy. Pricing should nevertheless ensure the end user still pays at least their individual avoidable costs.
(c)(ii) enable price/quality trade-offs.	Price/quality trade-offs may reflect various aspects of service quality, such as reliability, resilience, firmness, power quality, etc. This principle is to encourage distributors not to take a one-size-fits-all approach to service quality. In practice, the scope for price/quality trade-offs will depend on the realities of the network. For example, the reliability experienced by any single customer is almost always impacted by factors that will also impact the reliability experienced by other customers.
(d) Development of prices should be transparent…	This principle applies to both current and future prices. - Transparent application – The methodology used to derive current pricing should be transparent. Transparency helps develop consumer acceptance and helps consumers manage their electricity consumption. - Strategic change in pricing – The evolution of future pricing and its relationship to evolving circumstance should be clear to enable consumers to make significant and often long-lived investment decisions in an informed manner.
…and have regard to…	This clause lists practical considerations a distributor should turn its mind to as it develops prices. There should be evidence of the distributor having considered these issues, even if the result is no modification to intended pricing. Have-regard issues warrant serious consideration but do not override economic efficiency considerations – ie, they should fine-tune rather than dictate the approach taken.

Principle	Guidance
…transaction costs…	Transaction costs refer to the operational costs for all parties in the supply chain (distributors, acquirers and end users). They include direct costs (such as billing systems) and less tangible costs, such as the cost of interpreting and understanding prices, and deciding on responses.
…and consumer impacts…	Impact assessment is an important part of price design. Analysis of bill impacts at the consumer group level, including worst impacted end users (outliers), should be used to inform fine-tuning, transition design, and design of any impact mitigation measures. Bill impact assessment should include stress testing of how usage changes in response to new price signals might impact consumer groups and outlier revenue/bills. Distributors can seek information on broader aspects of consumer impact through engagement, or by leveraging industry processes. Retailer-relevant impacts may include items such as standardisation across networks, or business process preferences. End-user impacts can relate to matters such as communications and change processes and billing arrangements.

Principle	Guidance
…and uptake incentives.	In developing new pricing plans, distribution businesses should consider how customers will transition from their current pricing plans. The uptake of new plans will depend on: - pricing assignment policies - design attractiveness - eligibility hurdles. Assignment policies can include (in roughly increasing order of effectiveness): opt-in, ratcheted opt-in (ie, cannot opt back out), opt-out (automatically assigned but can revert), event-based (eg, consumers are assigned new pricing plans when they move properties or install generation), and automatic assignment. A soft approach can work if moving to new prices is always favourable and there is a natural prompt – for example, electric vehicle pricing. Designs that adopt industry standard features are more likely to attract uptake. In other cases, a more active approach may be needed, and can be complemented by transition techniques such as phased introduction (eg, introducing a new price structure with small differentials that are rebalanced over time). Eligibility hurdles, whether for end users or acquirers, can significantly dampen uptake incentives and should be avoided if possible.

The subsidy-free test

3.3 Distributors have adopted differing interpretations of how to apply the subsidy-free test:

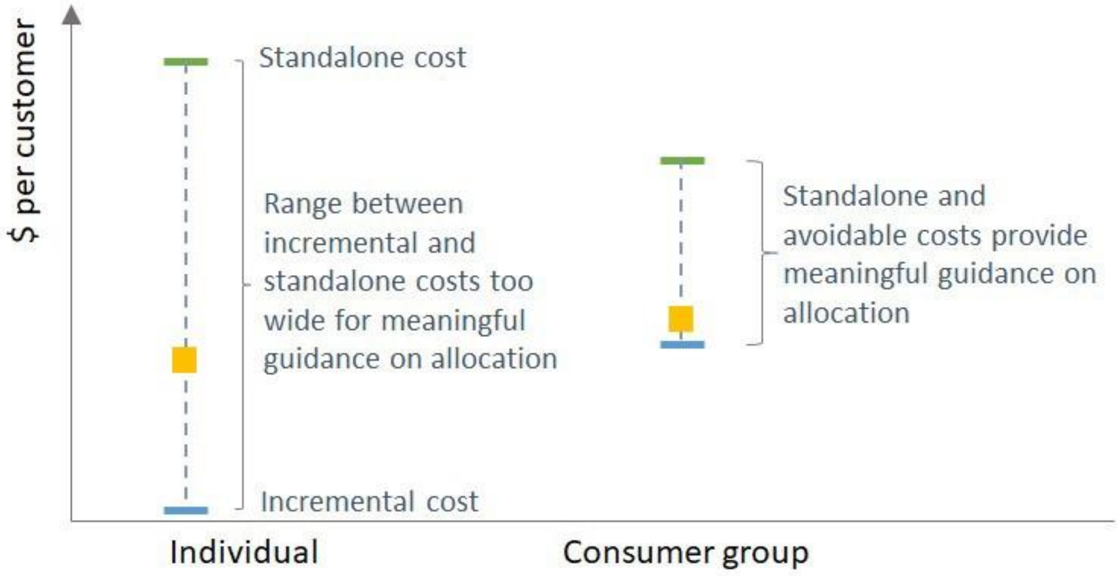
(a) individual level – in this version comparison is made between the prices paid by each customer and boundaries that reflect the cost of off-grid self-supply (standalone cost) and incremental costs from increased demand.

(b) consumer group level – in this version comparison is made between forecast revenue for each consumer group and boundaries that reflect the standalone costs of serving that consumer group and the avoidable cost of serving the consumer group.

3.4 In many circumstances, individual-level analysis does not usefully inform the allocation of costs because the bounds are very wide, as illustrated in Figure 2. Applying the subsidy- free test at the level of consumer groups may provide more practical, informative bounds on subsidy-free network pricing. For example, a micro-grid or other network alternative for an entire remote community is likely to be a more relevant comparator to network connection than a standalone solution for an individual consumer.

3.5 The Principles align more clearly with a consumer group-level analysis, because this provides a more intuitive and useful guide to residual cost allocation.

Figure 2: Comparison of subsidy test methods



Estimating standalone and avoidable costs[1]

3.6 Avoidable cost is estimated by considering how costs would reduce if a consumer group was not supplied with electricity. Examples of avoidable costs include:

(a) repair and maintenance costs

(b) customer service, billing, and metering costs, and

(c) transmission costs associated with contributions to peak demand (under the current transmission pricing methodology).

3.7 Standalone costs can be estimated by:

(a) investigating how individual consumers might generate their own electricity and/or their use of substitutes such as gas;

(b) allocating costs to different consumer groups based on estimates of their contributions to different network costs (such as their electricity use and the profile of their demand); or

(c) considering the costs of establishing hypothetical, standalone networks. For example, one could estimate the cost of separate rural-only and urban-only networks or hypothetical networks for residential-only and industrial consumers.

Defining consumer groups

3.8 The definition of consumer encompasses parties such as retailers, consumer agents and distribution-connected generators. As per the Electricity Industry Participation Code, consumers are supplied electricity for their own consumption.

1 For further discussion see Economic Concepts for Pricing Electricity Network Services, A Report for the Australian Energy Market Commission, 21 July 2014, https://www.aemc.gov.au/sites/default/files/content/f2475394-d9f6-497d-b5f0-8d59dabf5e1c/NERA-Economic- Consulting-%E2%80%93-Network-pricing-report.PDF.

3.9 Consumer groups are defined by a distributor as part of the price-setting process. The considerations for defining consumer groups are not directly addressed by the Principles but the approach adopted is an important part of achieving consistency. Consumers might be grouped by their energy usage, their location, their peak load requirements, or other characteristics, such as their ability to moderate load.

3.10 The following table sets out where consumer group definition can have a role in assisting to meet the principles.

Table 2: Considerations when defining consumer groups

Principle	Guidance
(a)(i) subsidy free	Target consumer groups to avoid averaging across very large differences in standalone and avoidable costs.
(a)(i) above avoidable cost	If consumer groups are very tightly targeted, then the per-connection avoidable cost of serving that group can become high. Larger consumer groups can support more pragmatic or socially acceptable assessment of subsidies.
(a)(i) less than standalone cost	If a network has pockets with high marginal costs it may be inappropriate to send that high marginal cost signal to all members of a broad consumer group since it may push group revenue above group standalone costs. More targeted consumer groups can allow appropriate cost signalling while keeping group revenue below group standalone cost.
(a)(ii) reflect impacts of network use on economic costs	Consumers can be grouped according to the economic costs they drive on the network. For example: □ daily profile □ seasonal profile □ interruptibility □ location (geographic or network topology)
(a)(iii) reflect differences in network service provided	Consumers can be grouped according to service differences. For example: □ connection capacity (peak demand limit) □ network support (service back to network) □ interruptibility

Principle	Guidance
(b) least distort network use	Consumers can be grouped to minimize the residual costs that might otherwise distort price signals. For example, pricing plans may look to group: - lower income households who are more likely to ration monthly expenditure - non-residential consumers who are more likely to respond to variable charge components
(c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation	Consumer groups may be defined to minimise the need for idiosyncratic negotiation of terms and conditions.
(d) transaction costs	Narrowly defined consumer groups may increase the operating costs of distributor and retailer billing systems and can increase search costs for end users (or deter search altogether).
(d) consumer impacts	By consumer impacts we mean the transitional costs as consumers adapt to new pricing plans. Consumer groups can be defined to manage impacts (eg, bill shock from rebalancing to higher fixed prices) or to reflect specific retailer circumstances or requirements. For example, consumer groups might be defined in line with retail prepay plans, or could be standardised across distributors to reduce billing complexity for retailers, and offer end-consumers more choice.
(d) uptake incentives	Distributors need to consider how to encourage consumers to move to new pricing plans. Criteria that determine whether a customer is eligible to be a member of a particular consumer group could promote or deter retail and consumer uptake. Some pricing changes are attractive and will attract consumers on an opt-in basis (such as pricing plans targeting consumers with electric vehicles). Large-scale changes to pricing plans often will not work on a purely opt-in basis, because of consumer inertia and because the terms may be unfavourable for some consumers relative to their existing pricing plans. Consumer acceptance might be increased by preserving legacy plans but making legacy pricing plans unavailable when a consumer moves properties.

3.11 In addition to the considerations above, consumer group definition may be driven by policy considerations, for example, to meet low-fixed charge regulation requirements.

Implications of price efficiency for pricing types

3.12 The Principles recognise that trade-offs are made in the pricing design. For example, the benefits of making prices responsive to location and peak load need to be weighed against the costs that arise from increased complexity.

3.13 Nevertheless, prices play an important role in allocating resources. We also expect pricing methodologies to improve progressively, prompting and accommodating changes to consumer behaviour and technology.

3.14 Price signals are more efficient if they are:

(a) targeted at the time periods that matter – distribution networks are under-utilised most of the time, so prices designed to signal losses, congestion, or future investment should target time periods when the network is most stressed

(b) tailored to local costs – marginal costs can vary significantly across a network, so prices designed to signal costs should be tailored to avoid big mismatches between the price signal and local economic costs

(c) reflect service differences – providing a price/service menu (eg, controlled vs anytime or 30A vs. 60A) is a powerful way to allow consumers to trade off service levels against cost of supply

(d) actionable – prices are more efficient if they are communicated and calculated in ways that consumers can respond to

(e) accurate – estimating economic costs is not straightforward and typically simplified methods are used that yield reasonably stable estimates over time. However, estimates should be reset (or more sophisticated methods used) when large divergences emerge between price levels and underlying economic costs

(f) non-distorting when aimed at recovering residual cost – residual cost recovery has the opposite goal to price signalling and should not influence network usage

(g) subsidy-free – the caveat for residual cost recovery is that total revenue recovered from each consumer groups should be within the bounds of avoidable and standalone costs, to avoid stimulating inefficient overall demand for service.

3.15 Table 3 compares the efficiency of prices for several commonly discussed pricing types. The discussion below mainly focuses on allocative efficiency. Distributors should also consider dynamic efficiency – how to transition pricing plans to adapt to changing technology, including increased use of demand management services, distributed generation, electric vehicles, and so on.

Table 3: Pricing types and efficiency considerations

Pricing type	Efficiency

Fixed daily charge	Efficient way to recover network costs when there is no need to signal economic cost of network use. Wholesale energy market prices give consumers a signal about the cost of energy.
Uniform variable (same $/kWh rate applies throughout every day)	Not targeted by time period at all. Simple, but may deter use when plenty of network capacity; does not send a relevant signal when the network is constrained.

Pricing type	Efficiency
Time-of-use (ToU) ($/kWh rate varies by pre-defined time blocks)	Provides a crude but actionable signal. More efficient in situations where network stress is consistent every day (in terms of timing and level). May require re-tuning as usage patterns adapt or economic costs change. High risk of deterring usage at times when economic costs are low.
Seasonal time-of-use (in blocks and/or rates)	More tailored than standard ToU. More scope to match signal to cost, and somewhat lower risk of deterring use at times when economic costs are low.
Customer peak or capacity ($/kW rate applied to booked, installed or measured peak demand)	Better aligned with the characteristic that drives capacity costs (ie, peak demand rather than usage). However, may not (depending on price design and network profile) differentiate between demand at higher- or lower-cost time periods.
Static network peak (rate applied to measured peak demand during pre-defined network peak periods)	Better aligned with biggest driver of the share of capacity costs (peak demand across a network area). Pre-set peaks make pricing more predictable. This may enhance response, but may also increase the likelihood of a false signal (eg, if actual peak occurs outside pre-set period).
Dynamic network peak (rate applied to measured peak demand during network peak periods)	Further improves targeting of price signal. Challenge to balance accuracy versus effectiveness – ie, locking in and communicating charging periods in advance enhances responsiveness and risk of false positives.

4 Concluding remarks

4.1 The information disclosure requirements and the reporting undertaken in relation to pricing principles guide the baseline information that distributors make publicly available. Distributors should nevertheless feel free to exceed these baseline requirements.

4.2 We encourage distributors to report any difficulties that they face in providing this information and any difficulties – regulatory or otherwise – that stand in the way of achieving efficient pricing.

5 Glossary

Avoidable costs	Avoidable costs are those costs that can be avoided by not serving a customer or customer group. Examples of avoidable costs include billing and customer service costs, connection costs specific to the customer or customer group, and additional maintenance costs.
Consumer groups	For pricing purposes, consumers will typically be grouped to have similar characteristics, similar network costs, and similar consumption profiles. Consumers within a group are typically subject to the same pricing plan.
Economic costs	The costs of providing the service, and any additional costs (externalities) borne by others (but not the producer).
Fixed costs	Costs that are invariant to the level of output. Eg, costs that are invariant to the amount of electricity sent down a network.
ICP	Installation control point – a point of connection at which the electrical installation for a retailer's customer is connected to a network.
Incremental costs	Incremental costs are the variable costs that arise from an increase in production or from serving additional customers. (See also avoidable costs.)
Locational marginal pricing	Pricing at different locations in the network, reflecting local demand and capacity, and the cost of getting electricity to a particular location. Also referred to as nodal pricing.
Marginal cost	The additional cost of producing one extra unit. In the context of distribution, typically the additional cost of serving one additional customer to the network, or the additional cost of increasing network capacity.
Network alternatives	Alternatives to investments in transmission and distribution, often to manage capacity constraints. Examples include demand management, interruptible demand, distributed generation, batteries, etc.
Non-distorting	An action or price is non-distortionary if it does not change the behaviour of consumers or producers. (Desirable for recovery of residual revenue.)
Over-recovery	A situation in which cost-reflective prices result in revenue greater than the costs of the network. (See also residual revenue and under-recovery.)
Residual revenue / residual cost	Revenue that augments the revenue obtained from cost-reflective pricing to ensure that fixed costs can be covered, so that firms do not make a loss. (Residual costs for consumers = residual revenue recovered by distributors.)
Revenue targets	Levels of revenue that distributors aim or are permitted to obtain. Eg, as determined by price-quality paths set by the Commerce Commission (where applicable).

Ripple-controllable demand	Demand management of consumer power consumption based on remote control of hot water cylinders.
Standalone costs	The costs needed to replicate or bypass a network entirely. If electricity prices are greater than a consumer's standalone cost then the consumer is better off by disconnecting from the electricity network and, for example, generating their own electricity or sourcing it elsewhere.
Subsidy-free prices	Prices are subsidy-free if they fall below standalone cost but are above incremental cost. A consumer paying a subsidy-free price makes some contribution to a distributor's fixed cost.
Under-recovery	A situation in which cost-reflective prices result in revenue that is less than the costs of the network. (See also residual revenue and over-recovery.)

Appendix C Appendix C: Transmission charge pass-through

October 2022

Executive summary

This practice note provides guidance on the treatment of transmission charges by distributors when setting lines charges, focussing on the new transmission pricing methodology (TPM) that will apply from April 2023.

This transmission charge pass-through practice note (TPT note) does not constitute compliance advice and should be read alongside the Authority's current Distribution Pricing: Practice Note.

The purpose of this TPT note is to assist distributors with implementation while encouraging efficient and effective pricing practices and supporting consistency and transparency.

The Authority's high-level guidance is that distributors should:

(a) **map transmission charges to pricing areas** – transmission charges should be allocated by pricing area. Locational variations in charge levels are a corollary of imposing benefit-based charges on new grid investments. These can be reflected in distribution pricing

(b) **use fixed charges where possible** – transmission charges should preferably be recovered through fixed lines charges, or charges designed to have limited influence on usage decisions

(c) **pass step changes through** – the TPM includes adjustment mechanisms that respond to large step changes in usage. These are amenable to being passed through to the customer whose actions prompted the adjustment

(d) **use proportionate allocation methods** – more complex methods may be practicable (and warranted) for large customers, while simpler methods are more appropriate for smaller customers

(e) **manage remaining differences by exception** – for the small proportion of customers for whom transmission and distribution connection are viable alternatives, distributors can address remaining uneconomic bypass risk through prudent discounts (or individualised pricing).

Where distributors are making judgements in applying this guidance, they should also bear in mind the following:

(a) transmission charges in the new TPM are intended to avoid providing incentives to users to alter their day-to-day use of the grid (ie, they are designed to be "fixed-like")

(b) allocation principles in the TPM differ between benefit-based and residual charges (allocation based on expected net private benefits from investments vs allocation to load customers based on their size)

(c) differences in charges between customers should reflect differences in their characteristics – ie, like customers should receive like charges

(d) accuracy of pass-through is more important for large and/or locationally flexible consumers, and for future (not yet committed) transmission investments, ie, where pass-through provides incentives to scrutinise investments

(e) pass-through methodologies and outcomes should be transparent, which will improve users' ability to understand their exposure to the cost of future transmission investments.

The balance of this paper covers the background to this TPT note, touches on relevant pricing concepts and provides more detail on each of the guidance points.

Contents

1. Introduction

1.1 From 1 April 2023, Transpower will begin recovering its costs using a new transmission pricing methodology (TPM). The new TPM embodies new logic for how transmission charges best work alongside nodal prices (and associated rebates) to promote efficient grid usage and investment. In a nutshell:

1.1.1. nodal price signals should coordinate grid usage, and influence investment decisions (eg, on where to build new generation or load and whether to invest in flexibility)

1.1.2. transmission charges should not influence usage, but the prospect of being allocated charges for new transmission investments should influence investment decisions

1.1.3. settlement residual rebates should avoid undermining usage and investment signals.[31]

1.2 Electricity charge components should work together coherently to provide the right pricing signals to customers and end users. Multiple elements are in transition:

1.2.1. the new TPM applies from April 2023

1.2.2. the Authority's real-time pricing project is intended to improve the effectiveness of nodal price signals, and is in its implementation phase now

1.2.3. distributors are progressing their own pricing reform with guidance from the Authority,[32] and

1.2.4. the Authority is working on a new settlement residual allocation methodology,[33] and avoided cost of transmission payments.[34]

1.3 Distributors will need to decide how they pass new transmission charges through to their customers. How they do so should be coherent with the distribution pricing principles and the logic of the TPM so that overall lines charges are effective at promoting efficient usage and investment outcomes.

1.4 Distributors have a variety of pricing methodologies and supporting logic, so outcomes will depend on how each distributor chooses to integrate the new transmission charges into their own pricing approach.

Purpose of the TPT note

1.5 The purpose of the guidance in this note is to:

(a) make implementation easier for distributors

(b) promote consistency across distributors

(c) guide the sector toward approaches that promote efficient outcomes.

1.6 Efficient usage and investment outcomes are promoted by well-structured and calibrated prices, and by transparency and consistency that helps retailers and end users understand, anticipate, and respond to prices.

1.7 The Authority expects distributors to apply the guidance in this note to the extent they can, recognising that full transition may not be achievable for the 2023/24 pricing year.

1.8 An assessment of distributors' application of the TPT guidance will form part of the Authority's future scorecard assessment of each distributors' pricing methodology. Where distributors depart from the TPT

T Nodal prices produce a surplus. Some of this is used in the financial transmission rights market, and the residue is returned to transmission customers.

32 The Authority publishes distribution pricing principles, and associated practice notes, to guide distributors but they are responsible for their own methodologies. The Authority has been working with the distribution sector to encourage evolution of pricing practices to ensure they remain fit for purpose (ie, as technologies evolve) and promote efficient outcomes. Many distributors have made progress in recent years toward these goals.

33 Refer https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/settlement-residual-allocation-methodology-sram/

34 Refer https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/acot-code-change-implementation/

guidance, we expect them to be able to explain why and to show how they are planning to work towards greater alignment over time.

Who is this guidance for?

1.9 The TPT note is written for two audiences:

1.9.1. distributors – to assist with design and implementation of changes to pricing methodologies for the 2024 pricing year (ie, the twelve months starting April 2023) and with planning for longer-term reform

1.9.2. customers (including retailers and end users) – to assist with transparency and predictability for consumers of electricity lines services.

Scope

1.10 Our immediate focus is on how distributors should pass through transmission charges when setting electricity lines tariffs. However, we consider this in the context of related pricing matters such as distributor's capital contribution policies (CCPs) and prudent discount policies (PDPs).

1.11 The TPT guidance does not consider:

(a) pass-through of settlement residue rebates – as of mid-2022, the Authority is preparing to consult on a new settlement residue allocation methodology (SRAM). As signalled in our January consultation paper we intend to consider pass-through of settlement residue as part of that work[35]

(b) pricing for distributed generators – the Code includes specific requirements for pricing arrangements for distributed generators.[36] The Authority is separately considering whether these need amendment or guidance on interpretation.

1.12 In preparing this TPT note, we considered the extent to which distribution prices should signal prospective transmission charges which the distributor expects to pay in future. This matter is out of scope for the TPT guidance, but we intend to further develop our guidance on signalling future costs as part of our wider pricing work.[37]

Structure

1.13 The next section outlines the high-level approach that distributors should keep in mind when reading and applying the TPT guidance. The following two sections cover relevant features of the new TPM, and distribution pricing principles and practices. The paper then provides TPT guidance, stepping through each of five high-level points.

High-level approach

1.14 In deciding how to allocate and pass transmission charges through to their customers, distributors should seek to preserve the TPM design principles outlined in the 2019 Issues Paper,[38] the 2021 Guidelines Decision Paper and the 2022 TPM Decision Paper, while making pragmatic compromises where needed to limit administration costs and to promote certainty. Key principles include:

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35 https://www.ea.govt.nz/assets/dms-assets/29/Settlement-Residual-Allocation-Methodology-principles-options-and-pass-through-consultation-paper-FINAL-2-v2.pdf

36 Refer Schedule 6.4 of the Electricity Industry Participation Code (the Code). Part 6 (ea.govt.nz)

37 Likely through further development of the Authority's Distribution Pricing: Practice Note

38 See especially para D.86 of the 2019 Issues Paper and related material

(a) transmission charges in the new TPM are intended to be fixed-like;[39] that is, a user is unable to alter its share of the cost of already built grid assets by altering its day-to-day use of the grid

(b) the benefit-based charge for each benefit-based investment is intended to be allocated between users in proportion to the net private benefits each user is expected to derive from the investment, as assessed at the time the investment is made

(c) the residual charge is intended to be allocated among load customers in a way that reflects their size (as a proxy for ability to pay) but does not influence usage

(d) differences in charges between customers should reflect differences in their characteristics – ie, customers with similar characteristics should pay similar charges.[40]

1.15 In addition, as more practical matters:

(a) Accuracy of pass-through is more important for:

(i) large and/or locationally flexible consumers

(ii) future transmission investments, for which there is still an ability to influence whether, when or how those investments will be made

(b) Pass-through should be transparent. This improves predictability, which in turn helps promote efficient investment coordination.

1.16 Where distributors are making any judgements in applying the guidance in this TPT note, these principles should inform their judgements.

39 This excludes two charges that are in the Guidelines but not the new TPM – the transitional congestion charge and the kVAr charge. These would be intended to influence use if they were bought into the TPM.

40 This means that the charges for new customers should be set by reference to the charges paid for similar existing customers.

2. Relevant features of the new TPM

2.1 Key ideas underpinning the new TPM, which are relevant to pass-through and allocation of transmission charges, are set out below.

Transmission charges *should not* influence grid usage

2.2 Grid users are exposed to locational marginal prices (LMPs or "nodal prices") that provide appropriate signals for coordinating grid usage. Transmission charges in the new TPM are designed to be fixed-like to avoid altering the efficient signal provided by LMPs.[41]

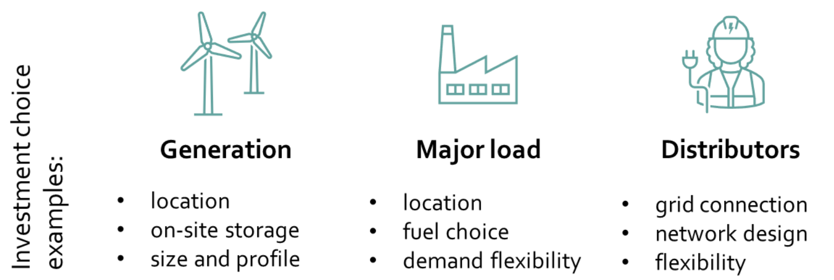
Connection charge	Standard method BBCs (high value projects)	Simple method BBCs (low value projects)*	Residual
Charge based on **asset characteristics**, not usage*	Fixed allocation of asset costs based on one-off* **benefits** forecast	Fixed allocation of asset costs based on historical **flows**. Reset every 5 years.	Fixed allocation based on historical* maximum gross **demand**. Annual update using lagged 4-year average demand**
* minor exception for shared asset costs (allocated on AMD/AMI)	* reopenable for major events (under-use, step-changes)	* also anticipatory connection capacity	* or estimated for new customers ** 4-year grace + 4-year ramp for new customers

2.3 For practical reasons, the charges do have some degree of linkage to usage – ie, a user who made a large or sustained change to their usage would (eventually) experience a change in their transmission charges. However, the design intent is to avoid influencing usage because this would detract from the efficiency of nodal price signals – ie, by deterring efficient consumption or production.

The *prospect* of future charges *should* influence investment

2.4 Investment coordination is enhanced if grid users consider their contribution to the need for future grid upgrades when making their own decisions.

2.5 This was already the case for connection assets under the prior TPM. Under the new TPM, grid users should also consider their exposure to benefit-based charges (BBCs) from future grid upgrades.



41 The 2020 TPM guidelines allow for variable charges (including a transitional congestion charge) intended to influence use of the grid, but no such charges are currently included in the TPM.

Locational variations in historical costs *may* influence investment

2.6 As a growing share of grid costs are recovered through BBCs, each connection location will end up with a different total transmission charge that reflects how many benefit-based investments (BBIs) it has been exposed to (and the value and age of those investments).

2.7 Locational variations in charge levels are a corollary of imposing benefit-based charges, rather than being the primary goal. However, the locational differences that arise are potentially helpful – ie, differences broadly indicate how dependent each location is on grid assets.

Other considerations

2.8 Alongside the key ideas above, the TPM features below are relevant to pass-through of transmission charges.

Charge adjustments

2.9 Due to its use of fixed allocations, the TPM includes several adjustment mechanisms intended to mitigate the risk of material disconnects arising:

(a) between the treatment of otherwise similar parties, or

(b) due to large differences between anticipated and actual use of an investment.

Transmission charge prudent discounts

2.10 To mitigate the risk of inefficient outcomes arising due to cost allocation, grid customers can obtain a prudent discount if they demonstrate that either:

(a) it would be feasible but inefficient for them to bypass the grid, or

(b) their charges are outside the subsidy-free range (ie, above their stand-alone cost of supply).

Granularity

2.11 Benefit-based charges are intended to work relatively intuitively on a prospective basis – ie, because they are based on assessing how much a user is expected to benefit from a planned investment.

2.12 Annual charges will however represent an accumulation of historical allocations that would be difficult to 'unpick' retrospectively, as that would involve stepping back through time to each investment and looking at what grid planners anticipated at that time.

2.13 Fortunately, such retrospective unpicking is not required because the pricing logic focusses on exposure to future charges as the primary mechanism for promoting efficiency.

3. Distribution pricing principles and practices

3.1 Transmission charges are classified as a 'recoverable cost' for distributors.[42] Distributors whose revenue is controlled can recover transmission charges through the prices they set,[43] and all distributors have an obligation to disclose the contribution that transmission charges make to their prices.[44]

3.2 Transpower advises distributors each year of the fixed monthly amount they will pay for tramsission charges. As such, the task for distributors when setting prices is to allocate a fixed target revenue amount across their customers – including across network locations, consumer types (for example, residential vs. non-residential and small vs. large) and price components (for example, daily and energy-based charges). Lower cost allocation to any given cohort implies higher cost allocation to other cohorts (and vice versa).

3.3 The Authority provides guidance on distribution pricing in the form of the Distribution Pricing Principles (2019) and the Distribution Pricing: Practice Note (edition 2.1, 2022).

3.4 In the practice note, the Authority sets out brief expectations for pass-through of transmission charges. These include that transmission charges are intended to send price signals that should be passed through as distribution charges that send the same price signal (and influence network use in the same way) as the transmission charge.[45]

3.5 Transmission charges should also be passed through in a way that is consistent with the distribution pricing principles, to the extent applicable. For example, each distributor's approach to pass-through should be transparent and understandable and have regard to consumer impacts.

3.6 Distributors are responsible for their own pricing methodologies, but report annually on alignment with the Authority's distribution pricing principles.

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42 https://comcom.govt.nz/__data/assets/pdf_file/0017/60542/Electricity-distribution-services-input-methodologies-determination-2012-consolidated-20-May-2020-20-May-2020.pdf

43 In practice, all distributors tend to set prices with reference to the maximum that would apply if their revenue were controlled. As such, pass through of transmission charges is near universal.

44 Refer clause 2.4.18(1)(d) of the *Electricity Distribution Information Disclosure Determination 2012* at Electricity-Distribution-Information-Disclosure-Determination-2012-Consolidated-version-9-December-2021.pdf (comcom.govt.nz)

45 See paragraphs 113 and 114 of the Distribution Pricing: Practice Note (edition 2.1, 2022) for current guidance on pass-through of transmission charges.

Distribution pricing principles (2019)

(e) 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.

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

(g) 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.

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

3.7 The principles (which are not prescriptive) focus on signalling economic costs – particularly principles (a) and (b). The Authority updated its principles in 2019 and has since published practice notes and regular 'scorecard' assessments to assist and encourage good pricing practice. There is considerable variation in distribution pricing – each distributor has evolved its own approach with a range of rationales, price structures and cost allocation approaches.

3.8 Traditional approaches tend to focus on allocating target revenue between locations and consumer groups[46] by applying allocators to accounting costs (opex and asset values). Residential and small business pricing structures are shaped by compliance with low fixed charge regulations – either directly, or due to 'anchoring' effects. Larger users may have complex pricing structures with components that mirror selected cost allocators.

3.9 In contrast, the more forward-looking approach that the Authority encourages involves structuring charges to signal the impact of usage on avoidable network costs, such as congestion, footprint expansion, or capacity upgrades. Allocation of residual revenue to consumer groups then emphasises simplicity and the goal of limiting further influence on network usage.

3.10 Either approach works in conjunction with capital contribution policies, which recover dedicated asset costs and (sometimes) a contribution to upgrade costs for shared network assets, and prudent discount policies (or other non-standard pricing), which aim to mitigate uneconomic bypass risk.

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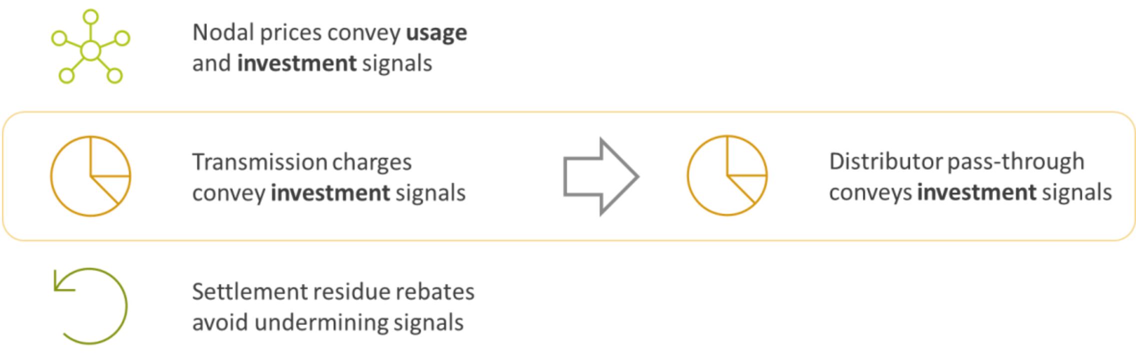
46 Consumer group refers to a group of consumers with the same tariffs – ie, it's the most granular level at which tariff schedules operate.

4. TPT Guidance

4.1 The new TPM aims to work with nodal pricing to coordinate transmission investment and usage, including by avoiding doubling up on the usage signals provided by nodal prices. The result should be efficient coordination of both investment and usage.



4.2 Distributors should also structure lines charges to promote efficient transmission network usage and investment – including by exposing customers (retailers or end-users directly) to transmission investment signals and avoiding sending usage signals for existing transmission assets.

4.3 To that end, the following high-level points flow from consideration of TPM logic and distribution pricing principles:

(a) **map transmission charges to pricing areas** – transmission charges should be allocated by pricing area. Locational variations in charge levels are a corollary of imposing benefit-based charges on new grid investments. They are potentially helpful, and can be reflected in distribution pricing

(b) **use fixed charges where possible** – transmission charges should preferably be recovered through fixed lines charges, or charges designed to have limited influence on usage decisions

(c) **pass step changes through** – the TPM includes adjustment mechanisms that respond to large step changes in usage. These are amenable to being passed through to the customer whose actions prompted the adjustment

(d) **use proportionate allocation methods** – more complex methods may be practicable (and warranted) for large customers, while simpler methods are more appropriate for smaller customers

(e) **manage remaining differences by exception** – for the small proportion of customers for whom transmission and distribution connection are viable alternatives, distributors can address remaining uneconomic bypass risk through prudent discounts (or individualised pricing).

4.4 The balance of this guideline provides more detail on each of these points.

(a) Map transmission charges to pricing areas

4.5 Transpower calculates and communicates transmission charges by location, so it should usually be relatively straightforward to allocate transmission charges to pricing areas.

4.6 By pricing area, we mean the geographic zones that a distributor uses to set its tariffs. Many distributors have a single pricing area, while others may have a pricing area for each 'network region'. For example:

4.6.1. Unison has two pricing areas – Taupo/Rotorua (with 4 grid connection locations) and Hawkes Bay (with 3)

4.6.2. Powerco has four pricing areas for smaller customers – Valley (with 6 connection locations), Tauranga (with 4), Western A (with 7) and Western B (with 9) – plus at least 12 pricing areas for larger customers (each mapped to one or more connection locations)

4.6.3. Wellington Electricity has a single pricing area with ten grid connection locations.

4.7 Depending on their pricing area setup, a distributor may have to map charges from one grid connection location to multiple pricing areas, or between pricing areas and customers with individual pricing. In those cases, the TPT guidance on proportionate methods in section (d) is relevant.

4.8 We note that situations could also arise where it is preferable to spread residual or specific benefit-based charges across a wider set of pricing areas – for example, where a distributor faces lagged charges relating to a large customer who has exited the network[47] In such cases, the key consideration is which treatment best supports the intent that cost recovery should not influence usage.

Why?

4.9 The new TPM aims to influence user investment choices by encouraging users to consider their exposure to the cost of *future* grid upgrades. This is directly efficiency enhancing because it influences behaviour before irreversible investment decisions are made.

4.10 Once new grid capacity has been built, there is arguably a downside to high fixed charges because they may put new end users off from making use of the newly expanded capacity. However, locational variations in transmission charges are a corollary of benefit-based allocation and can be beneficial because variations broadly indicate how dependent each location is on grid assets.

4.11 Mapping transmission charges to pricing areas means that each pricing area will face a different level of transmission charge allocation, and relative levels will shift over time for a range of reasons:

4.11.1. evolution of transmission charges – over time, a growing share of Transpower's costs will be recovered through benefit-based charges and the residual charge will decline

4.11.2. amount of grid – every location differs in the amount of grid assets (both connection and interconnection) that it benefits from. This can change over time, including as generation and load further afield evolves

4.11.3. lifecycle – the benefit-based charge for any asset is highest when it is near-new and declines as the asset ages. When assets are renewed their associated charges increase

4.11.4. growth – grid upgrades add to the amount of grid a location benefits from (and involve building new assets with relatively high charges).

4.12 All things being equal, a location will (in the long-term) have higher average charges if it "uses" more grid. As such, passing locational variations through into lines charges can potentially be helpful and, in any event, is a transparent approach.

4.13 In addition, allocating charges to pricing areas will, all things being equal, reduce the difference between charges for distribution versus transmission connection options. This is:

4.13.1. an enabling step for cost reflective allocation to consumer groups (ie, to groups within each pricing area), and

4.13.2. helpful for reducing incentives for uneconomic bypass risk.

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47 This is discussed further from paragraph 4.45.

(b) Use fixed charges where possible

4.14 The charges in the new TPM are all designed to be fixed (or fixed-like) from a user's perspective – that is, a user has limited ability to influence their charges by altering their usage.

4.15 Transmission charges should be passed through to lines charges that are similarly fixed such as:

4.15.1. per day (or month) – these may vary between consumer groups, while remaining fixed from any individual user's perspective (ie, short of moving consumer groups)

4.15.2. per day per unit of connection capacity – most distributors define consumer groups using capacity bands, but fixed charges can instead use a rate that varies with installed (or contractually defined) capacity. Including transmission charge pass-through within such rates would be reasonably fixed-like[48]

4.16 In practice, at least initially it may not be appropriate or possible for distributors to fully recover transmission charges via fixed lines charges because:

4.16.1. low-user low fixed charge (LFC) regulations cap the maximum fixed charge for households with low annual usage, and the cap may be below the level a distributor would otherwise use to recover their own network costs

4.16.2. the fixed vs. variable structure of charges for households with higher usage can be indirectly constrained by the requirement to ensure a household with demand at the low-user threshold is agnostic as to whether they're assigned to a low-user or standard consumer group[49]

4.16.3. household charges may have an 'anchoring' effect to the extent distributors try to avoid otherwise similar users having markedly different price structures – for example, to avoid encouraging small businesses to present as households

4.16.4. distributors may limit year-to-year changes in fixed charges to manage bill impact or hardship for low energy users, or to mitigate other potential adverse impacts of high fixed charges (such as excessive temporary disconnection activity).

4.17 The first year of the new TPM is the second year of a five-year phase-out of LFC regulations. As such, it's possible distributors will at least partly variabilise transmission charges for certain consumer groups for several years.

4.18 Preferably, where variabilised lines charges are used to recover transmission charges they should be low and uniform – that is, a charge that applies to energy (kWh) consumed at any time of the day or year.

> **Example**:
>
> A distributor allocates \$5 million of annual transmission charges to a consumer group with 35,000 customers consuming an average of 8,000 kWh per year (ie, a total of 280 GWh for the consumer group).
>
> The distributor would prefer to use fixed charges but due to the LFC regulations it can only recover \$0.15 per day per customer through daily charges – ie, around \$1.9 million for the year. The distributor decides to recover the balance through a \$0.011 per kWh charge that applies uniformly across both peak and off-peak time periods.

48 This type of charge can be made more fixed-like by using a lagging measure of capacity. The TPM uses lagging measures for the residual charge, with the aim of discounting the benefit of changing energy use.

49 Refer to clause 9 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.

4.19 Note that recovery via fixed charges does not mean that all customers pay the same amount, because distributors allocate customers to consumer groups, each of which may have a different fixed charge. Consumer groups cannot span pricing areas and may further break pricing down by type (eg, residential vs. non-residential) and size.

> **Example:**
>
> A distributor has two pricing areas, each with five consumer groups – residential, streetlighting, and three sizes of non-residential (small, medium, large). It also has one very large customer on individual pricing.
>
> The distributor sets six different $/day charges for the residential, streetlighting and small non-residential consumer groups.
>
> The distributor sets four different $/day/kVA rates for the medium and large non-residential consumer groups.
>
> The distributor sets a single $/day rate for the very large customer.

4.20 Although we don't deal with pricing for distributed generation in this TPT guidance, we note that the TPM residual charge clearly should not be passed through to generators, even as a fixed charge.

Why?

4.21 Nodal prices already include a transport component that sends an efficient, real-time signal regarding the economic cost of using the transmission grid as it exists today – a cost that is typically very low unless parts of the grid are congested.

4.22 Transmission charges recover costs of already-built assets, so converting them into usage-based distribution charges inefficiently deters usage of available capacity (ie, over and above the signal from nodal prices).

4.23 A distributor *could* try to influence its exposure to residual charges (and simple method benefit-based charges[50]) through a concerted and sustained effort to deter usage, but this would simply shift costs to other grid customers without reducing Transpower's costs while encouraging inefficient rationing by its own customers – ie, it would do more harm than good.

4.24 As such, the Authority discourages converting transmission charges for existing assets into usage charges.

4.25 If transmission charges must be converted into usage charges, then spreading annual charges evenly across every hour in the year should produce the least influence on usage (and hence cause the least harm).

4.26 Setting different charges for each consumer group means the fixed charge can vary by customer size, while limiting influence on usage.[51]

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50 The TPM includes 'standard' and 'simple' methods for allocating benefit-based charges. The simple method is used for lower-value (but potentially high volume) investments and relies on Transpower periodically assessing historical grid flows as a proxy for benefit.

51 Noting that if customer groups are based on a size metric (such as connection capacity) then there can be risk of unintentionally influencing customers near the boundary between higher and lower-cost consumer groups. The design of the charges should seek to limit such incentives.

(c) Pass step changes through

4.27 The TPM includes two mechanisms that adjust charges for large step changes in usage.[52]

Step change	References	Description
Plant connects, disconnects, upgrades or de-rates (BBC)	Cl 85 DP at 8.33-8.34 IP at B.234-B.237	If a large (>10MW) embedded plant connects or disconnects, Transpower must treat this like a 'notional customer' at the relevant connection location. This notional customer's BBCs are used to adjust the relevant connection customer's BBCs.
Plant increases usage (BBC)	Cl 86 IP at B.234-B.237 (incl. footnote 237)	If there has been a substantial sustained increase[53] in electricity consumed by a plant, Transpower must treat this increase as if a 'notional new customer' has connected new plant to the relevant connection location. This notional customer's BBCs are then added to the relevant connection customer.

Note:
Cl = TPM clause (New TPM (ea.govt.nz))
DP = decision paper (2022 TPM Decision paper (ea.govt.nz))
IP = issues paper (2019 Issues paper (ea.govt.nz))

4.28 Both adjustment mechanisms require Transpower to 'look through' the grid connection and respond to the actions of distribution-connected end users – ie, there will be a clear link between the change in transmission charges and the actions of an individual 'notional' transmission customer.

4.29 It is practicable for distributors to pass these changes through to the party whose usage changed (ie, the notional transmission customer).

> **Example:**
>
> A new customer (**Customer A**) connects to a distributor's network, adding 15 MW of demand. Transpower reallocates BBCs as if Customer A were a notional new transmission customer with a demand of 15 MW connected at the 'electrically closest' point of connection. The distributor is allocated notional Customer A's BBC and its other BBCs are adjusted down.[54]
>
> The distributor previously paid transmission charges of $5 million and now has transmission charges of $5.2 million, made up of a $0.4 million BBC relating to Customer A and other charges of $4.8 million (comprising adjusted BBCs and unadjusted residual and connection charges).
>
> The distributor allocates the new $0.4 million BBC to Customer A, plus a $0.1 million share of connection charges. In total, Customer A is allocated transmission charges of $0.5 million in the first year. The distributor's other customers enjoy a 6% reduction (on average) in the transmission costs they are allocated.[55]

52 There are other adjustment mechanisms that relate to other drivers – ie, not step changes in usage. Those adjustments should flow through to a distributor's standard cost allocation approach. There is also a mechanism that adjusts changes if there is a 'substantial sustained change in grid use'. While this could be triggered by a single user, the resulting changes may require more case-by-case consideration.

53 Defined as an increase in annual electricity consumption (not attributable to a large upgrade of the plant) of at least 25% since BBI allocations were last calculated.

54 See clauses 83 and 85(2) of the TPM.

55 Transmission costs recovered from other customers reduces from $5 million to (5.2 - 0.5 =) $4.7 million.

In subsequent years, the distributor tracks the BBC allocated to the notional transmission customer and continues to pass this amount through to Customer A.

4.30 When passing through a reduction, a distributor may need to check whether passing through the full step change is appropriate. For example – the distributor may already be allocating the customer a relatively low share of transmission charges such that passing through the full step change would push their overall lines charges below the lower limit of the subsidy-free range.

Example:

An end user de-rates their plant, removing 15 MW of demand from a distributor's network. In this case, Transpower re-allocates BBCs as if the plant was a separate notional customer (with a separate BBC allocation) that now disconnects.[56]

Accordingly, Transpower allocates the distributor a $0.4 million negative BBC relating to the de-rated customer. This reduces the distributor's total charges from $5 million to $4.6 million.

The distributor had only been allocating its customer $0.45 million prior to the de-rating. Accordingly, the distributor determines that passing the $0.4 million reduction through in full would push the customer's lines charges much lower than otherwise similar customers, and very low relative to the burden borne by other consumer groups.

The distributor decides to pass through a $0.3 million reduction in year one – bringing the de-rated customer's charges down to $0.15 million. In following years, the distributor allocates costs in a way that preserves this benefit (reduction).

4.31 An important consideration for distributors is whether passing through step changes could introduce an arbitrary difference between the charges that apply for otherwise similar customers – ie, there may be a tension between the efficiency benefits of passing costs through in full, and the goals of like treatment for like customers.

Example:

A transport company (**Customer B**) plans to electrify its fleet and adds 11 MW fast-charging capacity at its depot (which previously had negligible demand). This triggers a new notional customer BBC, and a reduction in the distributor's other BBCs.

The distributor has another otherwise identical transport customer (**Customer A**) who made a similar investment prior to the new TPM and has other transport customers planning similar but smaller (<10 MW) investments in future.

Customer A had been allocated $50k of BBCs by the distributor, and a further $80k of connection and residual charges. Customer B is allocated $100k by Transpower for BBCs alone.

The distributor is concerned that passing the full $100k through to Customer B would be inequitable. As such, it reviews its allocation approach and decides that it should:

- transition BBC allocations upward over three years for its largest capacity consumer groups, to better align with the allocation implied by Transpower's calculation

56 See clauses 84 and 85(3) of the TPM. Whether Transpower would apply this treatment depends on the age of the BBCs and whether the customer has other ongoing operations. For more detail, refer to clause 85(4)-(6)

- soften the transitional burden on small customers by also phasing-in pass-through of reduced connection charge allocations to its largest consumer groups.

In accordance with its pricing methodology, the distributor will still consider the allocation of future large benefit-based investments on a case-by-case basis and will phase in allocation of residual charges for Customer B and any other large customers making large step changes.

Why?

4.32 Regardless of how a distributor normally allocates transmission charges, the adjustment events identified above have a clear causal link through to a specific distribution customer. They also involve large customers for whom:

4.32.1. parity with grid pricing is more important (because uneconomic bypass risk may be a real risk), and

4.32.2. the prospect of future charges is more likely to promote efficiency by influencing investment decisions – ie, because the customer's energy usage is material.

4.33 As such, passing step changes directly through to those customers is a proportionate approach and can promote efficient outcomes. However, two key considerations for distributors when passing through step changes are:

4.33.1. subsidy-free range – step changes should be assessed to ensure full pass-through would not result in a disproportionately high or low overall allocation (ie, that the pre-existing allocation plus the step adjustment does not make the customer a notable outlier, or push them outside the subsidy-free range)

4.33.2. equitable pricing – care should be taken to avoid introducing significant discrepancies between the costs allocated to otherwise similar end users.

(d) Use proportionate allocation methods

4.34 Due to the way the new TPM builds charges up from a series of benefit assessments, each of which can involve historical assumptions about future benefits, it is very difficult for cost allocation to faithfully mimic the basis for each component of a distributor's transmission charges.

4.35 In addition, the case for faithfully mimicking transmission charges is not strong. For most customers, the overriding priority is to ensure allocation methods don't inadvertently create incentives for customers to alter their usage of built grid assets – ie, because nodal price signals do a better job of efficiently coordinating usage.

4.36 The case for mimicking the TPM is strongest for large customers:

4.36.1. to ensure large differences in allocations do not become a driver for inefficient bypass for customers who are large enough that this is a realistic risk – this is relevant to charges for existing grid assets and future grid investments

4.36.2. so that incentives to coordinate investment flow through to distribution-connected customers whose usage is material enough that they may influence the size or timing of transmission investments – this is relevant to future grid investments only.

4.37 From the above considerations, it is desirable for distributors to adopt proportionate allocation methodologies, including for allocating costs:

4.37.1. between pricing areas (if applicable)

4.37.2. between consumer groups within each pricing area

4.37.3. potentially, to individual large customers

4.37.4. potentially, for large benefit-based or connection grid investments that have not yet been committed.

4.38 Having allocated costs to a consumer group level, each customer within a group should typically be allocated the same charge (ie, absent any step change pass-throughs, prudent discount agreements, or adjustments relating to capital contributions).

4.39 The following table illustrates three different allocation methods, ranging from most complex (A) to least complex (C).

Method	**Description**
A – Mimic BBCs	Methodology attempts to recreate basis for each standard method BBC . This includes inspecting the basis for each standard method BBC, which in turn links to Transpower's rationale for that investment – ie, this can involve understanding the scenarios and key assumptions Transpower has used when simulating how the investment would alter future market outcomes.
B – Mimic BBC metrics	Methodology uses a menu of allocation metrics (eg, prior year kWh, lagging average peak) and matches each standard method BBC to the most suitable metric.[57]
C – Single metric	Methodology uses a single allocation metric, such as prior-year energy (kWh) consumption.

4.40 When selecting which allocation metrics to use for simpler approaches to allocating fixed costs between pricing areas or consumer groups, a key consideration is how 'fixed-like' the resulting allocations will be. In general, the merit order for allocation metrics is:

4.40.1. consumer group or pricing area energy (kWh) – best. Least likely to inefficiently influence usage

4.40.2. consumer group or pricing area peak demand (kW) – less good because it can incentivise inefficient load shifting.

Example:

A distributor chooses prior-year energy (GWh) as a suitable metric for allocating (a) between pricing areas and (b) between consumer groups.

The distributor is comfortable that this approach will not influence usage for pricing areas or consumer groups with large numbers of small customers. For those consumer groups, the distributor divides the resulting allocation ($) by the number of customers in the group and allocates each customer the resulting fixed charge ($ per customer).

However, the distributor is worried that this approach may influence its largest customers to reduce their usage to reduce their allocation – these customers are large relative to their consumer group, so their actions make a material difference to the energy used by their group.

To mitigate this risk, the distributor modifies its allocation process. When allocating between consumer groups it combines the large customer consumer groups together. It then allocates

57 Note that we are describing here methods for allocating costs between consumer groups, and that care should be taken to avoid allowing the choice of allocation method to unintentionally influence customer usage. This risk is inherently higher with peak-based metrics, which are easier for a customer to influence.

between the combined consumer groups based on installed capacity. Finally, it allocates equally between customers in each consumer group.

Even with the modification, the distributor is worried that its very largest customer may still find it worthwhile to inefficiently modify its usage or connection capacity to influence the allocation outcome. To further mitigate this risk, the distributor uses average energy and connection capacity across four prior years for its largest customer.

4.41 Fully mimicking the TPM could be warranted for allocating the cost of large upcoming benefit-based investments (and potentially connection asset investments) to large customers. This involves interrogating the basis for new standard method BBC allocations and evaluating how a large customer's usage lines up with the investment rationale.

4.42 This could be an involved process given standard method BBC allocations are based on forecasts of various benefit types across a range of market development scenarios – ie, each large BBC is unique and Transpower's allocation process can be complex. As such, a relatively simple approximation that apportions the distributor's allocated charges using a forecast view of the applicable intra-regional allocator could be appropriate.

4.43 To be effective (and worthwhile) any such tracing should be carried out and advised to customers and end users at the same time Transpower consults on allocations for future transmission investments. This is because accurately mapping charges through to large customers is of most value if it creates the potential for better optimisation between user and transmission investment plans.

Example:

Transpower is considering a large benefit-based investment (BBI) and has indicated that 20% of the cost will be allocated to Distributor A across six connection locations. Transpower indicates that the investment is a peak BBI (ie, benefits mostly accrue at times of peak loading), with mean historical annual injection used as an intra-regional allocator.

65 Intra-regional Allocators

(1) Subject to subclause (2), the **intra-regional allocator** for a **regional customer group** under the **price-quantity method** is as follows:

type of **BBI**	type of **regional customer group**	**intra-regional allocator**	subclause
peak BBI	**regional supply group**	mean historical annual **injection**	(6)
	regional demand group	mean historical **coincident peak offtake**	(7), (8)
non-**peak BBI**	**regional supply group**	mean historical annual **injection**	(6)
	regional demand group	mean historical annual **offtake**	(5)

On closer inspection, the distributor realises that the 20% result is driven in large part by Transpower's view that demand growth will occur within Distributor A's network and that half of this growth expected to occur due to one large customer.

> The distributor engages with its large customer, and advises that, consistent with its pricing methodology, it intends to pass 50% of future BBCs for the new investment to that customer.
>
> In this example, the customer is allocated a higher share of this BBC than it would be for other investments (using the distributor's default method). The reverse could also occur (ie, a lower allocation than the default method).
>
> In any event, each year the distributor applies any tailored allocations first and should then use its simpler method to allocate the balance of its transmission charges.

4.44 Mimicking metrics provides an intermediate option, which may be suitable for consumer groups relating to very large customers – ie, for whom inefficient bypass is a material risk and/or for whom engagement with transmission investment processes is likely.

Residual charge phase-in and phase-out

4.45 The TPM residual charge presents a particular risk of prompting uneconomic bypass risk, because it has a multi-year phase-in (and phase-out) for new (or exiting) grid customers that may be difficult for distributors to fully replicate. This can be partially addressed through cost allocation. Doing so should reduce the need for distributors to manage uneconomic bypass risk.

4.46 There are three features of the residual charge to consider:

4.46.1. phase-in profile – a new grid customer will pay residual charges that phase in across several years. This broadly matches what would happen to a distributor's residual charges if the user instead connected to the distribution network. Distributors should match this phase-in profile for their large customers[58]

4.46.2. phase-out profile – if a ,, grid customer disconnects one site but remains a transmission customer, its residual charges will phase down across several years. Again, this broadly matches what would happen to a distributor's residual charges if the user were instead connected to the distribution network. Distributors should match this phase-out profile for their large customers[59]

4.46.3. disconnection – if a grid customer disconnects and ceases to be a transmission customer, Transpower will reallocate its charges to other customers. In contrast, if the user had been a distribution customer the distributor's residual charges will phase down over several years. The best a distributor can do in this circumstance may be to spread the phase-out costs across its remaining customers.[60]

Why?

4.47 It is not practicable to make transmission pass-through faithfully mimic the charges that every customer would experience if they were (hypothetically) directly connected to the transmission network. Reasons for this include:

4.47.1. transition profiles – in some circumstances, a customer connecting directly to the grid could experience a different phase-in profile for its new charges than a distributor would experience if the customer were embedded

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58 The Authority appreciates that passing through this phase in and out of the TPM residual charge is not realistic for a distributor's smaller (eg, residential) users, and notes that uneconomic bypass risk is substantially less likely for these customers.

59 This could involve a contractual arrangement that imposes a payment obligation that survives a customer's disconnection from the network.

60 A similar issue can arise with respect to BBCs – ie, where allocation to a distributor is influenced by the usage of a relatively large customer who subsequently exits.

4.47.2. vintages – each customers' charges are the product of unique accumulation of historical assessments of future benefits, assessments of grid flows, and adjustments. New grid customers are assigned charges that only broadly match other similar customers

4.47.3. benefit forecasts – the standard method allocates benefit-based charges based on bespoke assessments of future benefits. BBCs vary in the usage characteristics used to assign benefits, so a faithful pass-through would use a variety of allocation drivers.

4.48 The harm from cost allocation diverging from hypothetical direct connection charges is largest for large customers, so a proportionate approach is to adopt simpler methods for small customers and consider more complex methods for larger customers.

(e) Manage remaining differences by exception

4.49 Because it's not practicable for pass-through to fully mimic the charges a customer would face if it were transmission connected, differences in transmission versus distribution pricing could potentially provoke bypass if they are sufficiently material. Cost allocation should aim to mitigate this risk, but if this is not practicable, prudent discounts (or individual pricing) can be used as a fall-back to address residual risk.

4.50 Inefficient bypass risk arises when direct connection to the transmission system:

4.50.1. is feasible (ie, technically, legally, and commercially)

4.50.2. would cost less for the customer (ie, due to pricing differences)

4.50.3. would have a higher economic cost (ie, cost more to build and operate).

4.51 Prudent discounts should be used where alternative measures have been insufficient or are impracticable. The onus should be on the customer to demonstrate that all three of the above conditions are met and that, absent a prudent discount (or individual pricing), pricing differences would drive a customer to make an inefficient decision.

4.52 If a customer can make that case, then it is efficient for the distributor to enter an agreement that deters connection to the transmission network. Note that:

4.52.1. the assessment of whether transmission connection would cost less should consider the present value of future charges, not just the upfront or first-year difference in charges

4.52.2. it may also be relevant to consider how exposure to future charges differs between distribution and transmission options. The distributor may want to include more granular pass-through of future transmission charges in the prudent discount agreement, however

4.52.3. the agreement may not have to mimic transmission charges – for example, a distributor may prefer to apply a one-off credit or recurring discount rather than agreeing to permanently customise charges.