Pricing guidelines for electricity distributors

A handbook for pricing practitioners

September 2022

Contents

Version Control

Version	Date of Publication	Scope of Document
1.1	September 2015	Version one of the ENA Pricing Guidelines covered the following topics: • Definitions of small capacity consumer groups, including Residential and General (metering categories 1 and 2 in the Code commonly referred to as “mass market” consumers) • A definition of temporary supply • Definitions of common pricing plan components, including Uncontrolled, Controlled, Night Only, Night Boost, All Inclusive, Day and Night • Definition of Summer and Winter periods • Outlined standardised approaches to pricing documentation, terminology, schedules, and billing.
2.0	September 2016	Version two of the ENA Pricing Guidelines reflects some minor changes based on feedback received and extends the scope also to include: • Large Commercial pricing structures • Irrigation • Unmetered load • Power factor.
3.0	September 2022	Version three of the ENA Pricing Guidelines refreshed version 2.0 of the guidelines to reflect the following: • Electricity Authority’s Distribution Pricing Practice Note Second Edition, • Electricity Authority amendments to Schedule 12A.4, Appendix A, Default distributor agreement for distributors and traders on local networks (interposed) • ENA’s Guidance Paper for Electricity Distributors on new pricing options • Introduction of electric vehicle (EV) and photovoltaic (PV) tariffs • Phase-out of the low fixed charge regulations • Changes to the Transmission Pricing Methodology (TPM) effective 1 April 2023 • Implementation of Electricity Price Review recommendations by the Ministry of Business, Innovation and Employment (MBIE) and other Government bodies.

Glossary and Abbreviations

Authority	Means the Electricity Authority.
Commission	Means the Commerce Commission.
Connection	A point of connection to an electricity distribution network as identified by an Installation Control Point (ICP) identifier.
Consumer	Means any person supplied with or applies to be supplied with electricity other than for resupply, as per section 5 of the Electricity Industry Act 2010.
Controlled Meter	A meter with the functionality to measure and control the energy provided to permanently wired appliances (e.g., a hot water cylinder) connected to the meter.
Default Distributor Agreement Template (DDA)	Electricity Authority amendments to Schedule 12A.4, Appendix A, Default distributor agreement for distributors and traders on local networks (interposed).
DER	Distributed Energy Resources
Distributor	A company owns or operates the power lines that transport electricity on local networks. Terms also used are “distribution company”, “lines company”, and “network company”.
Electricity Industry Act 2010 (Act)	An Act that regulates the operation of the New Zealand electricity industry.
Electricity Industry Participation Code (Code)	The Code sets out the duties and responsibilities of industry participants and the Electricity Authority.
Electricity Information Exchange Protocol (EIEP)	EIEPs provide standardised formats for business-to-business information exchanges.
Electricity Networks Association (ENA)	Association of all 29 New Zealand electricity Distributors.
Electricity Price Review	New Zealand Government, Electricity Price Review, 21 May 2019.
HHR	Used by Traders to identify that the half-hour settlement methodology is applied to an ICP in the Registry.
Information Disclosure (ID)	Electricity Distribution Information Disclosure Determination set per Part 4, subpart 4 of the Commerce Act.
Input Methodology (IM)	Electricity Distribution Services Input Methodologies Determination as per Part 4, subpart 3 of the Commerce Act.
Installation Control Point (ICP)	See Connection.
Kilowatt hour (kWh)	A kilowatt hour is also known as a unit of electricity; kWhs are the basis of retail sales and reconciliation of electricity in the market.
Kilovolt-amps (kVA)	Kilovolt-amps is a measure of apparent power. It describes the total amount of power being used by a system.
Legacy meter	A meter measures energy consumption (kWh) cumulatively and does not have remote communications capability. Installed at a Category 2 ICP or lower (≤500Amps).
Low Fixed Charge Regulations (LFC Regulations)	Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2008, and Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2021.
Loss Factor	Loss factors are declared by distributors and used to reflect the normal difference between energy injected into a network and energy delivered from the network in the reconciliation process.
Low Fixed Charge (LFC)	Low Fixed Charge.
Lower South region	Stipulated in the LFC regulations as consumers supplied by Arthur’s Pass, Castle Hill, Islington, Bromley, Kimberly, and Hororata grid exit points, or any grid exit point located further south
Meter Categories (1, 2, 3, 4, and 5)	Defined in the Schedule 10.1 of the Code. See Appendix 6.
MEP	Meter Equipment Provider.
Meter register	An energy measurement device on a meter.

NHH	Used by Traders to identify that the non-half-hour settlement methodology is applied to an ICP in the Registry.
Peak Load	Peak half-hourly demand, measured in kW or kVA.
Pricing Note	Electricity Authority Distribution Pricing: Practice Note, Edition 2.1, 2022.
Pricing Principles	The Electricity Authority published the distribution pricing principles in its More efficient distribution network pricing – principles and practice, Decisions paper, 4 June 2019.
Registry	The Registry is a national database that holds information on all points of connection and embedded networks to which a consumer or embedded generator is connected.
Registry Content Codes	Descriptors in the Registry that define the functionality of a meter register.
ToU Meter	A metering installation capable of recording kWh and at least one of kVArh and kVAh on a half-hourly basis. Required on Cat 3 and higher installations.
Transmission	Conveyance of electricity at high voltages through the Transmission network.
Transmission network	Transpower New Zealand Limited owns and operates New Zealand's national transmission network (national grid).
Transmission Pricing Methodology (TPM)	Electricity Industry Participation Code Amendment (Transmission Pricing Methodology) 2022.
Uncontrolled Meter	A meter that measures load where there is no load control functionality.
Unaccounted for Energy (UFE)	The difference between reported energy injected into a network and the reported energy extracted from the network after adjusting for losses.

The Electricity Authority also publishes a glossary of key industry terms on its website at https://www.ea.govt.nz/glossary/

1. Introduction

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These guidelines are published by the Electricity Networks Association (ENA) to support the standardisation of definitions, formats, and structures used in electricity delivery pricing (the ENA Pricing Guidelines). Though the principal audience of these guidelines is the pricing practitioners of electricity distribution businesses, i.e., distributors, it is hoped that the guidelines will also prove helpful to electricity retailers and other stakeholders.

1.1 Purpose and scope

These guidelines help distributors describe and present their prices clearly and consistently for use by retailers, particularly those that operate across multiple network areas. The guidelines may also assist consumers in understanding more about the distributors' delivery charges that apply to them.

These are the third version of the ENA Pricing Guidelines. We have refreshed the ENA Pricing Guidelines to reflect the changes to the electricity industry since 2016, including the following:

- Release of the Authority's Practice Note
- Mandating of the DDA by the Authority under the Code
- Publication of the ENA's Guidance Paper for Electricity Distributors on new pricing options
- Introduction of electric vehicle (EV) and photovoltaic (PV) prices
- Phase-out of the LFC regulations
- Changes to the TPM, effective 1 April 2023
- Implementation of the New Zealand Government Electricity Price Review recommendation.

The guidelines are reviewed and updated when underlying regulatory framework changes or opportunities arise to achieve more consistent approaches to pricing.

1.2 Structure of these Guidelines

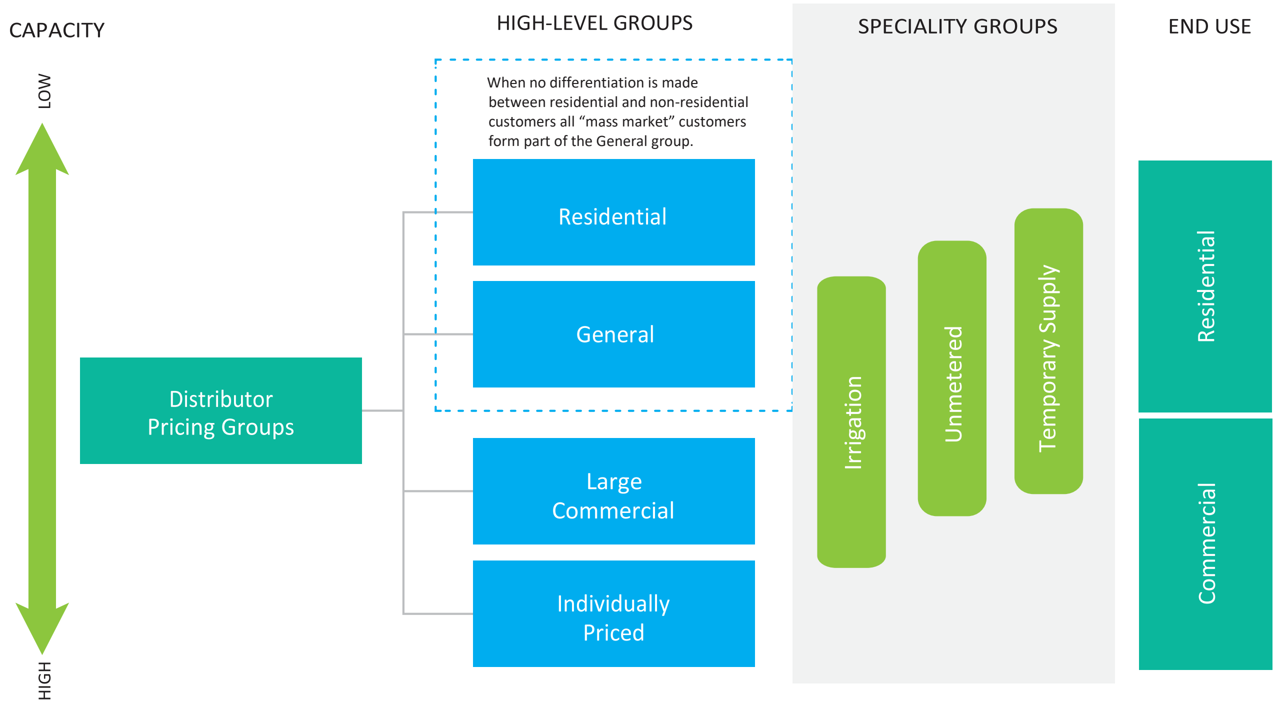
These Guidelines are structured as a handbook for distributors to reference when setting prices and considering their overall pricing strategies.

Cost-reflective pricing is a forefront industry issue. We have provided an overview of the concepts around cost-reflective pricing in chapter 2.

Broadly distribution charges can be broken; charges have been broken into five pricing groups. Figure 1 illustrates the pricing groups commonly used by distributors and expanded in the Guideline.

> The ENA Pricing Guideline is a valuable tool for facilitating increased standardisation across distributor pricing schedules by promoting common definitions, language, and formats.

Figure 1. Connection Types and Pricing Group



- Residential (including Low Fixed Charge plans)—is discussed in chapter 3
- General—is discussed in chapter 4
- Large commercial— is discussed in chapter 5
- Individually priced connections— are discussed in chapter 6
- Specialty pricing groups— are discussed in chapter 7.

Distributors prepare an array of documentation. Standard terms that promote consistency and simplify pricing documentation are outlined in chapter 8.

Billing format and processes differ depending on if a distributor uses ICP or GXP based pricing methodologies. An overview of both methodologies is provided in chapter 9.

1.3 These guidelines apply to ICP and GXP based pricing

Some distributors use ICP-based pricing, and others use GXP-based pricing.

- ICP- based pricing approach is based on variable consumption (i.e., kWhs) at each ICP based on the volumes provided by the retailers through the EIEP1 and EIEP3 files[1].

[1] Electricity Authority, EIEP1: Detailed ICP billing and volume information, Regulated, effective from 1 April 2021.

- GXP-based pricing approach is based on variable consumption at the grid exit point (GXP). It uses each retailer's volume reconciled under the energy market as a chargeable quality for distribution charges.

These guidelines do not form a view on the merits of ICP verse GXP pricing as this is a decision for individual distributors. These guidelines' discussion, recommendations, and information are price base agnostic. However, some of the recommendations and discussions within these guidelines only apply to distributors using ICP-based pricing, not GXP-based pricing.

1.4 Exempt and non-exempt EDBs can use these guidelines

All distributors can use the approaches outlined in these guidelines whether they are “exempt” or “non-exempt” under the price-quality path.

The price-quality path applies to 16 of 29 distributors. The price-quality path promotes outcomes consistent with workably competitive markets, i.e., incentivises distributors to provide the expected level of services at prices consumers are willing to pay.

The purpose of the price-quality path is to influence the behaviour of distributors by setting the maximum total allowable revenue that can be collected through prices. While the price-quality path sets a cap on total revenue, it does not specify how distributors attribute costs to consumer groups or how prices must be structured. Distributors are discouraged from increasing profits by decreasing service levels through imposed quality standards. Performance under the price-quality is reported annually, and there are significant penalties for not adhering to the price-quality path.

When setting the regulatory framework, the legislature decided that price-quality regulation need not apply to consumer-owned distributors and exempted those that met the criteria of consumer-owned[2]. These exempted distributors are called “exempt;” all other distributors are called “non-exempt” for the purposes of price-quality regulation.

These guidelines are price-quality regulation agnostic; accordingly, distributors can adopt the recommended approaches regardless of their exempt or non-exempt status.

1.5 Using the ENA Pricing Guidelines

The ENA Pricing Guidelines represent a view of pricing definitions and formats that distributors can adopt when setting prices, reviewing pricing methodologies, and publishing pricing schedules.

[2] Section 54D of the Commerce Act 1986.

The guidelines present either a single pricing approach or, in some cases, a list of suggested options. While it is anticipated that distributors will endeavour to align their pricing with the ENA Pricing Guidelines as far as practicable, it is acknowledged that distributors are free to adopt different approaches to suit local circumstances as they see fit. In this respect, the ENA suggests that distributors explain the reasons for their alternative approach in their pricing methodologies.

The guidelines do not replace the need to consult on changes to pricing structures

These guidelines are not a substitute for the consultation processes in clause 7.4 of the Default Distributor Agreement (the DDA) shown in Figure 2.

Figure 2. Consultation process at clause 7.4 of the DDA

> **Process to change Pricing Structure**: If the Distributor intends to make a change to its Pricing Structure that will materially affect the Trader or 1 or more Customers, the Distributor must first consult with the Trader about the proposed change. If appropriate, the Distributor may consult jointly with the Trader and all other traders that are affected by the proposed change. Without limiting anything in clause 7.3, and unless the parties agree otherwise, the Distributor must:
>
> (a) **comply with the Code**: comply with any provisions in the Code relating to the pricing of Distribution Services; and
>
> (b) **notify Trader of final Pricing Structure**: provide the Trader with information about the final Pricing Structure and the reasons for the Distributor's decision, in a manner that clearly sets out the change made, at least 40 Working Days before the change comes into effect.

Where distributors provide their services under the DDA, they must consult with retailers per the terms of clause 7.3 and also ensure that they comply with the Code before implementing any pricing structure changes.

2. Cost-reflective Pricing

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"Cost-reflective pricing" is the setting of prices to recover the economic costs of electricity distribution services. Prices are cost-reflective when they reflect the underlying drivers (i.e., causes) of the costs to serve. For example, a consumer's actions that drive or reduce network costs should also increase or reduce distribution charges for that consumer accordingly. Costs include the cost of investment in existing infrastructure and current and future costs. Cost-reflective prices should include a pricing signal for existing and new network capacity and be free of cross-subsidies.

In 2019 the Authority released its first Practice Note[3]. The note encouraged distributors to evolve their legacy prices to become more cost-reflective. Since 2019 the Authority has updated its Practice Note twice, once in December 2021[4] and a second time in May 2022[5]. These guidelines refer to cost-reflective pricing and the Authority's Practice Note throughout.

2.1 Why have cost-reflective pricing?

Cost-reflective prices are the cornerstone of efficient pricing. Efficient prices signal to end-users, and other participants, the most efficient use of the existing network and future network investments. Efficient use of distribution networks leads to lower costs to serve and lower prices for electricity consumers over the long term.

Efficient pricing is important as New Zealand delivers its decarbonisation goal as a low-emissions economy. Pivotal to realising this goal over the next 30 years is the electrification of transport and process heat.

Cost-reflective pricing can significantly increase price sophistication and complexity. The level of cost-reflectivity is a matter of practicality that each distributor must determine for themselves based on their network's circumstances and characteristics. Accordingly, these guidelines make no recommendations for the degree of cost-reflectivity.

The Authority recognised that there are trade-offs when considering the level of sophistication and complexity to apply to prices, as shown in Figure 3.

Figure 3. Recognition of complexity trade-off when setting cost-reflective prices

> We expect trade-offs when balancing complex pricing with other aims. For example, a theoretically most efficient price signal from 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.[6]

[3] Electricity Authority, Distribution Pricing: Practice Note, August 2019.
[4] Electricity Authority, Distribution Pricing: Practice Note, Second Edition, 2021, December 2021.
[5] Electricity Authority, Distribution Pricing: Practice Note, Second Edition 2.1, 2022, May 2022.
[6] Supra n5, paragraph 50 on page 10.

2.2 Distribution pricing principles

To support efficient pricing, the Authority released its 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.[7]

The Authority assesses distributors' prices against the distribution pricing principles.[8]

2.3 Pass-through of Transmission charges

In April 2022, the Authority released its:

- Electricity Industry Participation Code Amendment (Transmission Pricing Methodology) 2022 (the new TPM), and
- Transmission Pricing Methodology 2022, Decision paper (the TPM Decision Paper).

The changes to the TPM will take effect on 1 April 2023.

Outline of the transmissions charges three cost components

Transmission charges are made up of three cost components:

1. Connection
2. Benefit Based
3. Residual

[7] Supra n5, Page 3.
[8] The Authority's assessments can be found on its website at www.ea.govt.nz/operations/ditrbution /pricing

4. Provisions for adjusting transmission charges

Connection Charges

The approach to connection charges is largely unchanged by the new TPM. Connection charges for particular connection assets will continue to be paid by the customer or customers connected to them.

Benefit Based Charges

The new TPM allocates costs of new and certain historical grid investments to customers in proportion to their benefit. Benefits include giving consumers access to cheaper, more reliable electricity supply and generators access to bigger markets. Benefit-based charges (BBCs) recover capital and operating costs (including a share of overhead opex) attributable to a benefit-based investment.

Residual Charges

Residual charges recover Transpower's revenue not recovered through other transmission charges. The charge is to be paid by all transmission customers to the extent they are load customers, including grid-connected generators with an embedded load. Initial allocations are updated over time, with a significant lag to minimise grid use and investment distortions.

Provisions for adjusting transmission charges

The new TPM has made the following provisions for adjusting transmission charges[9]:

- general adjustment provisions—provides for step adjustments where is a substantial and sustained change in grid use, such as when a customer enters or exits the grid;
- reassignment provisions—provides for a BBI to be "reassigned" if the forecast future loading is substantially less than the BBI's capacity, i.e., the BBI is deemed to be over-sized ex-post;
- a prudent discount policy—provides two prudent discounts:
  - an inefficient bypass prudent discount (IBPD) ensures that customers are not incentivised under the TPM to invest in an alternative project (e.g., an alternative line or new generation) to bypass the network, where it would be inefficient overall to do so; and
  - a stand-alone cost prudent discount (SACPD) ensures the TPM does not result in a customer paying transmission charges that exceed the efficient stand-alone costs of the transmission services received by the customer.
- a transitional cap—applies to the distributor's and grid-connected consumer's BBCs for the seven historic BBIs and residual charges relative to the interconnection and HVDC charges for the 2019/20 pricing year—

9 Transpower, Guide to the new TPM

- broadly, set at 3.5% of total line services during the 2019 pricing year, increasing by 2% each year after the 2024/25 pricing year; and
- applies to each pricing year up to and including the 2037/38 pricing year under a 'use it or lose it' mechanism whereby the cap ceases to apply from the pricing year at which the customer transmission charges falls below the cap.

Passing through transmission charges

The changes to transmission pricing are significant and have taken over a decade to finalise. Distributors pass-through Transpower's charges for transmission services to customers (i.e., retailers and direct billed consumers). Distributors will need to consider how the changes to transmission pricing will impact their price-setting approach.

The Authority has provided high-level guidance on the pass-through of transmission charges

In its Practice Note, the Authority provided its expectations for residential and small commercial consumers, as shown in Figure 4.

Figure 4. Transmission charges extracted from the Practice Note.

a. fixed transmission charges, which are not intended to influence customers' network use decisions, should be passed through as fixed (daily) distribution charges[10]
b. transmission charges 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[11].[12]

Applying the Authority's approach, a distributor would allocate costs based on kWh (i.e., a variable allocator) and recover costs through a fixed charge. This hybrid approach highlights the inherent practicalities of distributors passing through transmission charges as promoted by the Authority.

The Authority has also released a summary of high-level guidance in the passing through transmission charges by distributors.

1. **map transmission charges to pricing areas**
2. **use fixed charges where possible**
3. **pass step changes through** (arising from the TPM adjustment mechanisms)

[10] This would include the proposed benefit-based charges and residual charges, which are intended to be largely a fixed charge.
[11] An example could be 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 the future.
[12] Supra n5, paragraph 113 on page 20.

4. **use proportionate allocation methods** – generally more complex methods for large customers; simpler methods for smaller customers
5. **manage remaining differences by exception**, eg, offering prudent discounts for genuine uneconomic bypass risk.

Practicalities to consider when acting on the Authority's guidance

The LFC Regulations require, amongst other things, distributors to set one low fixed daily charge that is of no more than the amount specified in the regulations (more discussion on LFC regulations can be found in chapter 3 in section 3.1 of this Guideline). While the 'cap' rises annually until 2027, the practicalities of the LFC Regulations are that it limits the ability of the distributors to pass-through transmission costs to all residential customers through a single fixed charge. Making it difficult to mechanistically follow the Authority's guidance when passing through transmission charges.

> **Distributed generation has specific limitations**
> The pass-through of transmission charges to distribution generation (DG) connection are subject to the incremental cost provisions under schedule 6.4, Part 6 of the Code.

The approach that distributors take to pass-through transmission costs must take account of each distributor's circumstances and be reflected in their pricing strategy, policies, and decisions as communicated in their Pricing Methodologies. These Guidelines do not recommend a single pass-through approach; we suggest distributors apply a principle-based approach to their decision-making.

We consider there to be two key principles

We consider there to be two key principles underpinning the pass-through of transmission costs by distributors:

- Principle 1—distributors should not attempt a detailed replication of the allocation approach used in the TPM. Rather the allocation approach should be consistent with and have regard for the allocation approaches adopted by the TPM. In practice, this can be achieved by adopting the same underlying allocation drivers of demand (AMD) and usage (kWh) share.
- Principle 2—the pricing structures for the recovery of transmission costs should reflect the non-distortionary principle (prices should not influence the ongoing use of the grid) as outlined by the Authority in its Practice Note (extracted in Figure *4* above) and implicit in the fixed charge adopted by the TPM.

Recommend approach to pass-through transmission costs

As discussed above, there is no one pricing approach that all distributors can take to pass-through transmission charges. Pass-through approaches must take account of each distributor's circumstances. As an aid to distributors in 1, based on our key principles above in Table 1, we have provided a summary of an approach that distributors could use to pass-through transmission costs.

Connection charges

The approach to connection charges has not changed under the TPM. Accordingly, we recommend that distributors retain their existing methodology for allocating connection charges to pricing groups.

Historically, the primary allocation tool used by distributors has been anytime maximum demand (AMD). And the costs of connection charges have been recovered through fixed prices, e.g., $/ICP/day or $/kVA/day.

Benefit Based charges

The Authority has voiced a strong preference for distributors to recover costs through fixed or “fixed-like” charges. BBCs are not intended to influence the existing customers' use of the transmission network. To the extent practicable, we recommend that distributors recover BBCs through fixed charges (i.e., daily charge per ICP, installed capacity per kVA, or a similar fixed charge approach).

The allocation of benefit-based costs within the TPM is conducted using complex benefits modelling. Accordingly, it is not practical for distributors to replicate the allocation of benefit-based costs to pricing groups. However, underpinning the TPM’s complex allocation of benefits is a simpler approach that uses regional kWh usage.

Simpler allocation approaches that distributors can use when allocating benefit-based costs to pricing groups include by share of historical kWh, demand or capacity.

Residual charges

As with BBCs, residual charges are not intended to influence the existing customers' use of the transmission network; again, we recommend that distributors recover these costs through fixed or fixed-like charges to the extent practicable.

The TPM allocates residual charges firstly by historical AMD and secondly by kWh. It is appropriate that distributors use either approach when allocating residual charges to pricing groups.

The TPM allocation approach is complicated by applying a lagged approach to new customers. New load customers will not pay a residual charge until it has been connected to the grid for at least four years. The new load customer’s residual charge will then ramp up over the next four years adjusted based on lagged average gross energy usage.

Distributors may, but are not obligated to replicate the TPM approach

Distributors do not have to replicate this approach; however, if choosing to do so, they will need to consider different pricing groups, depending on how long existing customers have been connected; and for new customers.

The residual charge should then be allocated to each customer group based on their share of the maximum demand based on historical or estimated future maximum demand.

Where a distributor chooses not to differentiate customers by connection date, we recommend allocating the residual charge to pricing groups by share of gross AMD or kWh. An example of how a distributor may pass-through transmission costs is shown in Table 1.

Bespoke commercial arrangements for large users

The new TPM's lagged approach to the allocation of charges means that where a large customer ceases to be connected to the distribution network the EDB will continue to be charged transmission changes as though the customer is still connected for four years with the charges then phased out overs the subsequent four years. To mitigate the impact of the exit of a large customer on the distributors remaining customers, the distributor could consider establishing bespoke commercial arrangements (i.e., bank bond or letter of credit) with its large customers to recover post exit transmission charges from the customer exiting.

Table 1. Example approach of transmission pass-through

Charge Type	Basis of the cost	Transpower's Allocation Method	Charged to distributors	Allocation to Price Categories	Allocate within Price Categories	Charge to customers
	Step 1 *Transpower*	*Step 2* *Transpower*	*Step 3* *Distributor*	*Step 4* *Distributor*	*Step 5* *Distributor*	*Step 6* *Final price structure*
Connection	Connection investments	Primary: location/connection Secondary: Demand	Fixed	Demand (AMD)	Small: ICPs (avg. AMD) Medium: ICPs (avg. AMD) Large: Demand (AMD)	Fixed Fixed Fixed - individually calculated
Benefit Based	Interconnection investment	Primary: Regional Benefit Secondary: GXP kWh (avg.)	Fixed	kWh usage	Small: ICPs/kWh Medium: ICP/kWh Large: kWh	Fixed/kWh Fixed Fixed – individually calculated
Residual	Remaining recoverable revenue	Primary: Historical average AMD Secondary: Historical average kWh Tertiary: Lagged system kWh (avg.)	Fixed	AMD or kWh usage (unlagged)	Small: ICPs/kWh Medium: ICPs/kWh Large: kWh (unlagged/lagged)	Fixed/kWh Fixed Fixed – individually calculated

2.4 Future prices

Decarbonisation is changing the very foundations of the New Zealand economy. Electrification of transport and process heat has been identified as our leading opportunities to decarbonise. Facilitating this represents a step-change in the electricity supply chain. New Zealand will need more renewable generation, transmission, and distribution infrastructure to deliver its part of New Zealand's zero-carbon economy.

"Future prices" is a generic term used to identify prices that are yet to form part of a distributor's standard services, for example, prices for emerging services. Services in New Zealand include:

- charging of electric vehicles (EVs) on mass in both the domestic and commercial sectors;
- a disaggregated embedded generation or grid-scale batteries injecting onto networks; and
- emerging non-network solutions, e.g., flexibility services, load aggregators, and demand-side response (DSR).

Future service costs are unknown. Accordingly, these guidelines provide principles that distributors can adopt when setting their future prices but do not prescribe methods for setting future prices.

Have regard for the Authority's distribution pricing principles

As a matter of good pricing practice, distributors should apply the Authority's distribution pricing principles when setting future prices. Currently, the Authority does not prescribe how distributors must set prices; this includes setting future prices. However, the Commerce Commission's information disclosure requirements require distributors to disclose how their prices comply with the pricing principles or don't, as the case may be.

Distributors should be prepared to justify future prices that do not align with the Authority's pricing principles by including a description of the misalignment and how it is in the long-term benefit of consumers in their pricing methodology.

Efficient pricing has a role in future prices

Distributors must be mindful of sending the right signals when setting future prices. The wrong pricing signal can encourage consumer behaviour, resulting in a perverse outcome. For example, it would be inefficient to set time of use pricing, with significant price differentials between peak and off-peak periods, to an unconstrained network or a network that does not have an emerging constraint.

In its Practice Note, the Authority discussed the window of opportunity concept applicable to designing effective prices that supports the electrification of New Zealand's economy. The 'window' identifies the relationships between increasing demand, cost-reflective pricing and pricing signalling, customer investment, investment by distributors, and the emergence of non-network alternatives (e.g., flexibility traders). The ‘opportunity’ arises from understanding the timing of the distributor's and customers' decisions. A ‘window of opportunity’ exists where customers respond to pricing signals that result in the efficient deferral or avoidance of network investment.

Figure 5 provides the three potential pricing scenarios to which the concept of window opportunity could apply, as outlined by the Authority in its Practice Note.

Figure 5. The Authority’s 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

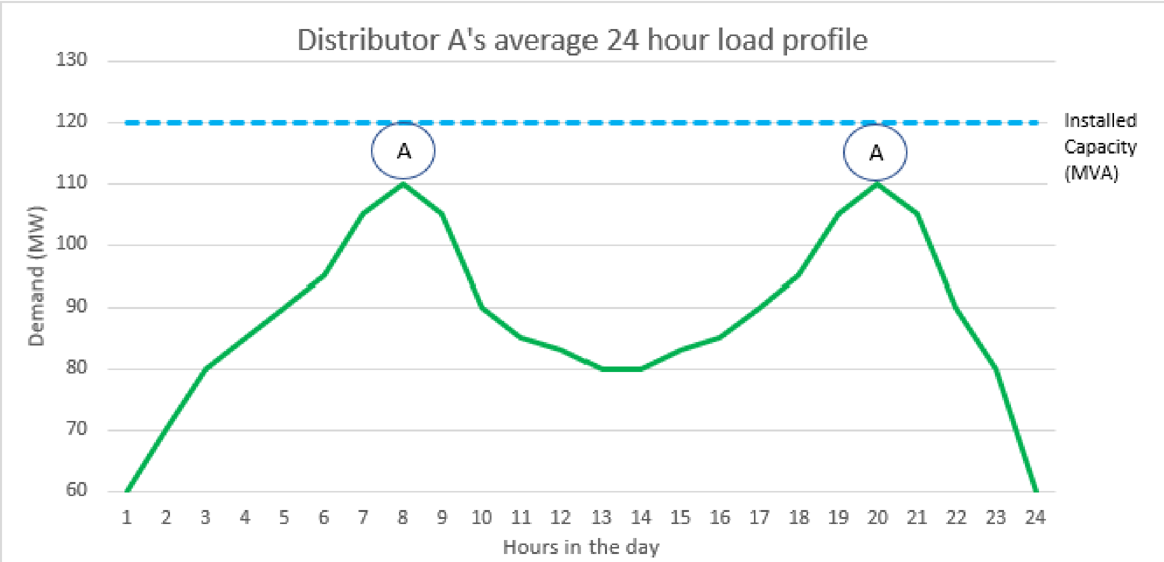
If demand is not expected to create a network constraint within the ‘window of opportunity’ then no immediate price signal is required.[13]

The window of opportunity explained

The window of opportunity is specific to each distributor and is determined by each network’s characteristics and asset management framework. For example, Figure 6 shows a fictitious distributor's average 24-hour load profile; “Distributor A”. Distributor A has an installed capacity of 120 MVA. On average, Distributor A will experience two peaks at 8:00 AM and a second at 9:00 PM of 110 MW, observable at points A.

[13] Supra n5, paragraph 33 on page 8.

Figure 6: Distributor A's average 24-hour load profile



Assuming that the growth on Distributor A's network is forecast to be:

- 1MW per annum in the year 0 to 4 (i.e., BAU growth),
- 2 MW per annum from year 5 to year 10 (i.e., early growth due to decarbonisation), and
- 3MW per annum between years 10 and 15 (i.e., continued growth due to decarbonisation).

Distributor A's forecast peak demand can be plotted over time, the intersection with installed capacity can be foreseen, and the window of opportunity becomes evident.

Figure 7 shows Distributor A's 15-year forecast peak demand (based on the trend of the observable peaks) and its installed capacity assuming no network augmentation. The graph shows that all other things being equal between years 0 and 4, Distributor A's network is unconstrained under BAU growth forecasts; however, from year 5, a network constraint emerges as the peak demand increases in response to the growth from New Zealand's decarbonisation policies taking effect (i.e., the electrification of transport and process heat). If Distributor A takes no action, forecast peak demand will intersect with an installed capacity in year 7. From year 8, Distributor A's network becomes constrained as forecast peak demand exceeds installed capacity. The constraint increases as growth in forecast peak demand continue under New Zealand's decarbonisation policies.

Figure 7: Distributor A's average 24-hour load profile

For Distributor A, a window of opportunity exists between years 1 and 7. This window gives Distributor A time to enact policies (e.g., encourage flexibility service) that could push the intersection of forecast peak demand and installed capacity out several years (i.e., the opportunity). If the intersection of forecast peak demand and installed capacity period is less than 5 years, there is no window of opportunity for Distributor A. Its ability to defer augmentation has been eroded because augmentation lead times necessitate it to build now or risk not having the installed capacity to meet forecast peak demand in time for the foreseen intersection.

A deferral strategy remains relevant until the point at which the forecast peak demand intersects the installed capacity. At this point, Distributor A must augment the network to meet forecast peak demand. If Distributor A can push deferral out more than 15 years, they might encourage long-term investment in alternative network solutions. On the flip side, considering lead times to design, procure, and build networks, deferral of fewer than 5 years is likely to result in network augmentation being the only option available to Distributor A.

Identifying the window of opportunity and sending an appropriate pricing signal is not derived from guaranteeing a demand response. Rather, the benefit is derived from encouraging customers to consider their willingness to change their demand.

Future prices should be set on drivers of cost

To be efficient future prices should be set based on the driver of the costs to serve. Future costs can include allocating a portion of current (direct and indirect) and forward-looking costs, including avoided costs.

Current costs are backward-looking and easier to identify than forward-looking costs as they are historical. Forward-looking costs are more difficult to identify as these costs have yet to occur. A common method for setting forward-looking costs is to use marginal cost pricing.

Marginal cost can be defined as the change in a firm's total cost divided by the change in the total output. The rationale for using marginal costs is that future costs can be influenced by changing the current or predicted behaviour that drives forward-looking costs. An increase (or decrease) in demand can be met through capital investment. Capital costs related to network augmentation can be managed efficiently by bringing forward, deferring, or avoiding changes to the capacity needed to meet demand changes.

Two commonly used marginal cost approaches are short-run marginal costs (SRMC) and long-run marginal costs (LRMC).

Short-run marginal cost concept

SRMC is the cost of supplying an additional unit, assuming at least one factor of production is fixed. Electricity distribution networks have times of peak and off-peak electricity demand, but the capacity of the distribution system does not instantaneously adjust, as capacity is fixed. Accordingly, the SRMC for an electricity distribution network remains constant until further output cannot be produced without expanding capacity (i.e., augmenting the network).

For example, a distributor with a peak constraint augments their network and adds capacity. Following the capacity extension, the distributors' SRMC would fall to zero but rise to full cost as capacity is utilised and exhausted. If the distributor adds new investment, the installed SRMC will again fall to zero.

This investment pattern results in 'saw-tooth' unstable and 'inefficient' changes in the long-term. To combat inefficient investment, distributors signal their SRMC through peak load pricing, such as ToU prices.

Ideally, distributors will apply their ToU pricing so that all consumers pay the price equal to the marginal cost of service (electricity distribution provision). Consequently, prices are equal to the marginal cost and benefits during all phases of the demand cycle (peak and off-peak periods). Assuming that idle capacity exists in off-peak periods, off-peak users will not get any benefit from the capacity extension. However, the peak period users will benefit from the capacity extension, and the SRMC pricing principle requires that peak period users pay for it.

The optimal pricing rule will have consumers pay the price equal to the marginal cost of their consumption, e.g., different prices for different phases of the demand cycle (peak and off-peak periods).

Regulators generally prefer LRMC over SRMC because of SRMC's saw-tooth changes and instability. LRMC better reflects electricity distributors' large network investments when augmenting their networks.

> "…the term LRMC is used to signify the cost effect of a change which involves some alteration in the amount or timing of future investment. SRMC, on the other hand, takes capacity as given, so relates only to changes in operating costs..."[14]

The electrification of New Zealand's economy to meet its decarbonisation goals is likely to require distributors to augment their networks to meet the step change in demand. Making LRMC a more appropriate marginal cost approach for distributors to apply to price, particularly future prices.

Long-run marginal cost concept

The Authority favours the use of LRMC over SRMC as LRMC aligns with its principle that prices should not distort the network usage decision of the customers as discussed in Figure 3 above.

LRMC applies the principle that customers will be encouraged to use the network only if it is economically desirable. With the technological changes, the cost of alternatives (e.g., solar and batteries) are expected to steadily decrease over time, pushing customers towards cheaper non-network solutions.

Setting distribution prices on the principle of "non-distortionary network usage" requires distributors to retain investment incentives to upgrade or extend the existing network when new and cheaper technology is available. Accordingly, investment decisions will focus on areas where it is "efficient" to upgrade the network, and non-network solutions will be encouraged in those areas where network investment is "inefficient".

Utilities use three common approaches to estimate the LRMC:

- the marginal incremental approach (MIA)—the difference in the present value (PV) of the investment program with and without an incremental increase in demand;
- the perturbation approach, also known as the "Turvey" approach—estimates the PV of the change in forward-looking costs that arise from a marginal and permanent change in forecast demand; and
- the average incremental cost approach (AIC) estimates the PV of forward-looking costs arising from forecasted demand exceeding current demand.

Marginal incremental approach

The MIA approach is useful to distributors with no network capacity or emerging constraints (i.e., network augmentation is some time in the distant future). This is because MIA does not look beyond the next investment block and ignores the effect on unit costs of subsequent increases in output. A disadvantage of

[14] Annex A: Some comment on Ofwat's Long Run Marginal Costs paper, Ralph Turvey, pg. 62

MIA is that it has the characteristics of short-run marginal costs, e.g., exhibiting instability and the potential for saw-tooth changes.

Perturbation or "Turvey" approach

Turvey marginal cost is based on the axiom that, given some growth in demand, additional capacity increments cannot be avoided but can be postponed (advanced) with reductions (increases) in annual demand.

The Turvey approach is useful to distributors with incremental (or decremental) changes in demand. This is because the approach takes the difference between two-time streams of the minimum total cost, each corresponding to a different level of demand.

Average incremental approach

AIC is the PV of the capital expenditure (Capex) stream divided by the PV of the demand stream. It can be illustrated as—

(NPV Capex)/(NPV Demand)

AIC is useful to distributors as it removes the MIA's lumpiness and smooths out expenditures.

Turvey and AIC approaches are contrasting. Under the MIA, the capital expenditure only relates to the next augmentation, and the demand is the incremental demand in the first year. Under the AIC, demand for the whole planning period is accounted for.

Criteria to evaluate LRMC concepts

The decision as to which LRMC approach to adopt will depend on the circumstances of the future price and the characteristics of the distributor's network. Accordingly, these guidelines do not recommend an LRMC approach to distributors. Table 2 lists distributors' criteria to evaluate which LRMC approach represents the best fit.

Table 2: Criteria to evaluate a best fit LRMC approach

Criteria	Description
Demand efficiency	Consumers are charged no more or less than it costs to provide additional capacity. Charging above this will result in consumers paying too much and consuming too little. Charging below this will result in consumers paying too little and consuming too much. Charging at the marginal cost to serve results in the use of service at efficient levels.
Supply efficiency	The distributor must recover sufficient costs to sustain the provision of services consumers require. For electricity distribution, costs to serve are mostly fixed, and future pricing that recovers only the incremental costs of the service would be inadequate, and eventually, the distributor would fail. Services can be priced by apportioning the costs for base services and incrementally recovering the costs of services above the base.
Theoretical foundation	Future cost concepts and methodologies must be based on a solid theoretical framework. Many concepts and methodologies apply to natural monopolies, such as water services, gas, and electricity. Many, like LRMC, are interchangeable between utilities and are universally recognised and defendable.
Fair and objective	Future prices should reflect the cost to serve and be equitably distributed. Fairness and objectivity (or equity) can be particularly difficult for electricity, which has been considered a social good since its mass roll-out in the 1950s. Economic judgments are not normally concerned with whether prices are equitable but merely describe the consequences of consumer behaviour as judgments of efficiency. All other things being equal, the same price should be charged for the same level of service where the costs to serve are the same. However, this maximum may not hold for socio-economic reasons, and different prices might be charged to different consumers for the same level of service and quantity. Such circumstances should be reflected in the LRMC approach chosen.
Transparency and reliability	Future pricing must be explainable, credible, and defendable to stakeholders (i.e., consumers, shareholders, and regulators). Keep pricing simple, but no simpler than it needs to be. Complexity will decrease price transparency and increase the potential for error.
Practical and understandable	Future prices must be understandable, easy to use, and practical. The efficiency gains from more disaggregated prices must exceed the transaction costs (i.e., administration and management costs) of implementing them. LRMC is not a precise science, and the choice of approach should include an assessment of the accessibility of the inputs to apply the chosen approach.
Flexibility	Future services are uncertain, and setting future prices requires us to set prices for emerging services, or we do not have clarity yet. Future prices should be flexible to change as assumptions are updated and confirmed. When applied to different circumstances, the chosen LRMC approach should be adaptable and sensibly yield different outcomes.

3. Residential Group

3. Residential Group

The rationale for adopting a residential pricing group, defined by end-use, is that these consumers often have similar required capacity, a common load profile, and electric hot water load is often controllable by the distributor.[15]

The terms "domestic consumer" and" domestic premises" are defined in section 5 of the Electricity Industry Act 2010 (the Act), shown in Figure 8, and the term "domestic consumer" is defined in section 4 of the LFC Regulations, shown in Figure 9.

Figure 8. Definitions of domestic consumer and premises - s5 Electricity Industry Act

> Electricity Industry Act 2010
> (5) Interpretation
> In this Act, unless the context otherwise requires,—
>
> domestic consumer means a person who purchases or uses electricity in respect of domestic premises
>
> domestic premises means premises that are used or intended for occupation by a person principally as a place of residence; but does not include premises that constitute any part of premises described in section 5(c) to (k) of the Residential Tenancies Act 1986 (which refers to places such as jails, hospitals, hostels, hotels, and other places providing temporary accommodation).

Figure 9. Definition of domestic consumer – s4 LFC regulations

> LFC Regulations
> 4(1) Interpretation
> In these regulations, unless the context otherwise requires,—
>
> domestic consumer means any person who purchases or uses electricity in respect of his or her home.

These guidelines, however, recommended distributors adopt the term "residential" and apply a definition consistent with the statutory definition of domestic consumer and domestic premises in section 5 of the Act. The term "residential" is commonly used by utility service providers and understood by electricity consumers.

3.1 Residential group definition

A residential connection is a supply to a consumer connection primarily used as a private dwelling (i.e., a home) or intended for occupation principally as a place of residence. The term "home" is defined in s4 of the LFC Regulations, as shown in Figure 10.

Figure 10. Definition of home – s4 LFC regulations

> LFC Regulations
> 4(1) Interpretation

[15] Distributors usually offer a range of control options, and some distributors also mandate that storage water heaters must be connected to the network via a controlled circuit.

In these regulations, unless the context otherwise requires,—

home means the domestic premises (as defined in the Act) that are the principal place of residence of a domestic consumer.

Accordingly, a principal place of residence is a dwelling that is occupied as (or provides service to) the consumer's primary residence and therefore excludes a holiday home or an additional home that is not the consumer's principal place of residence (even if regularly occupied). A consumer can only have one principal place of residence.

Residential connections exclude jails, hospitals, hostels, hotels, communes, or other temporary accommodation[16].

Residential consumers are entitled to a Low Fixed Charge (LFC) pricing plan under the LFC Regulations (discussed in more detail in section 3.1). LFCs can be applied to all residential consumers as a single pricing group or a residential connection group sub-group.

3.2 Classifying "residential" connections

Bed and Breakfast operations, Airbnb, and other occasional rentals

A Bed and Breakfast operation would not meet the standard definition of a residential connection. However, it is less clear if a consumer occasionally advertised a room in their home on, say, Airbnb or their family holiday home on Bachcare, Homestay, or BookaBatch whether that connection should be included in the residential pricing group.

The residential group need not necessarily be applied as an absolute. It is appropriate that some discretion is applied when assigning connections to the residential group. The term 'principally' used in the Electricity Industry Act is subjective, leaving it largely up to the distributor to deem when a connection is and is not a domestic premise. For example, if a consumer rented out one room of their house for two weeks a year, would this mean that connection was no longer a domestic premise? What might be an acceptable threshold of 10%, 25%, or 50% of the time?

A less subjective approach might be to assess the connections usage pattern. Where activity exceeds the connection's usage pattern and capacity requirements, assigning that connection to another pricing group other than residential would be reasonable. However, where the activity is not impacting the connection usage pattern or capacity requirements, it might be reasonable for the distributor to classify the connection as residential.

[16] That is premises that constitute any part of premises described in section 5(c) to (k) of the Residential Tenancies Act 1986.

Include subgroupings for residential connections

A common approach to managing the mixed-use of residential connections is to have subgroups within the residential category. For example, a holiday home category or high-capacity residential category.

When setting subgroupings for residential connections, distributors must be mindful that the LFC Regulations (discussed in more detail in the next section) require all qualifying residential consumers to have a low fixed charge option, including those in subgroupings. Subgrouping should not be used as a workaround to the LFC Regulations. Any connection that is a domestic consumer's principal residence is eligible for a corresponding low fixed charge.

Where a distributor chooses to apply residential subgroups, these guidelines recommend that the context for the decision to apply a subgroup be included in the distributor's pricing methodology disclosure. The context will help consumers understand how the distributor applies the subgroup and how it might apply to their connection.

Water pumps or other ancillary facilities that are a separate ICP but support a residential connection

A water pump or other ancillary connection may service a residential connection in rural areas. If a separate ICP, the connection does not meet the definition of a residential connection outlined above. The standard approach would be for a distributor not to classify the ancillary ICP as a residential connection.

Mixed-use connections—business ran from home

The boundaries between business and residential activity can be difficult to define. For example, should a connection be in the residential group where one room in the home is used to conduct business, a beautician, accountancy, or consultancy? What if the occupant uses the garage for part-time car restoration, an art gallery opens on the weekends, or a dojo three nights a week?

Covid- 19 has blurred this line; further, a Work Futures Otago survey found that 67% of respondents would like to work remotely a few times a week or month[17]. Since 2020 New Zealand has seen exponential growth in start-ups and other small businesses, changing how New Zealanders use their homes' connections.

The application of the residential group need not necessarily be applied as an absolute. In these guidelines, distributors recommend discretion when assigning connections to the residential group. If an occupant of the residence 'works from their home,' which is a residential connection, and the usage pattern and capacity requirements are not impacted by the activity, then the standard approach would be for the distributor to classify the connection as residential.

[17] Work Futures Otago, Remote Working during COVID19, New Zealand National Survey: Initial Report July 2020, Page 4.

Small-scale community facilities

To support the communities they serve, some distributors offer exceptions by applying the residential pricing group to the end-use of small-scale community facilities, such as halls used infrequently by community groups. While well-intended, these connections do not meet the eligibility criteria for an LFC pricing plan set out in the LFC Regulations. Accordingly, the standard approach recommended in these guidelines is for distributors not to classify these installations as residential connections.

Instead, a general pricing group could be applied with comparable pricing to residential connections. Where a distributor chooses to provide comparable pricing, these guidelines recommend that the distributor include context for the decision to offer comparable pricing and the eligibility criteria in their pricing methodology. Such details will help consumers understand how the distributor applies comparable pricing and if the connection is eligible. More discussion on setting prices for a general pricing group can be found in chapter 5 of these guidelines.

3.3 Low Fixed Charge Group

The "LFC Regulations" consist of three regulations the—

- Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004;
- Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2008; and
- Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2021.

The objective of the LFC Regulations is shown in Figure 11.

Figure 11. The objective of the LFC Regulations

LFC Regulations (3) Objective,—
The objective of these regulations is to —

(a) Ensure that electricity retailers offer a low fixed charge tariff option or options for delivered electricity to domestic consumers at their principal place of residence that will assist low-use consumers and encourage energy conservation; and

(b) Regulate electricity distributors so as to assist electricity retailers to deliver low fixed charge tariff options.

The LFCs prescriptive and applied by requiring that:

- an LFC pricing plan has one fixed charge of no more than is prescribed by the LFC Regulations,
- an LFC pricing plan must be available to all consumers at their principal place of residence,
- a principal place of residence is the dwelling that is occupied as the consumer's primary residence and would therefore exclude a holiday home or an additional home that is infrequently occupied,

- where a specific LFC price category is provided, the consumer will pay the same on the LFC plan as they would on a standard plan; provided their annual consumption is less than 9,000kWh in the Lower South region[18]or less than 8,000kWh elsewhere in the country[19],
- the LFC Regulations do not set a capacity limit above which a residential connection is ineligible for an LFC plan; and
- distributors must offer any qualifying residential connection a low fixed charge compliant plan regardless of their capacity unless the distributor has an exemption.

Each characteristic is discussed in more detail in the following sections.

There can be only one fixed charge

Among other limitations, the LFCs limit distributors to charging only one prescribed fixed charge, which until recently was 15 cents per day. In 2021, the second Amendment Regulations came into effect, allowing for phasing out LFCs over five years. Section 3A of the Amendment Regulations allows distributors in—

- Year 1, to replace 15 cents with 30 cents — 1 April 2022 to the end of 31 March 2023
- Year 2, to replace 30 cents with 45 cents — 1 April 2023 to the end of 31 March 2024
- Year 3, to replace 45 cents with 60 cents — 1 April 2024 to the end of 31 March 2025
- Year 4, to replace 60 cents with 75 cents — 1 April 2025 to the end of 31 March 2026
- Year 5, to replace 75 cents with 90 cents — 1 April 2026 to the end of 31 March 2027.

The regulations will be revoked on 1 April 2027.

The prescribed limit of one fixed charge applies to the distributor's total fixed price, i.e., includes cost recovery for distribution, transmission, and other costs associated with delivering electricity distribution lines services.

Options when setting one fixed daily charge under the LFCs

The LFCs do not prescribe the method in which the one fixed daily charge under the LFCs is applied. While distributors tend to have a fixed daily charge per ICP, they are not precluded from setting the fixed charge on some other basis such as installed capacity per kVA; or some other fixed charge.

When considering alternative approaches to applying the fixed daily charge distributors, should be mindful of:

---

[18] Lower South region includes consumers supplied by the Orion, Electricity Ashburton, Alpine Energy, Network Waitaki, Aurora Energy, OtagoNet, The Power Company, or Electricity Invercargill distribution networks.

[19] Noting this must comply at each possible combination of price component codes e.g., UN/CN at 60/40, UN/Night at 75/25, or just UN.

- the availability of accurate and timely information about domestic connections,
- under the LFC Regulations, the average consumer pays no more per year on a low fixed charge tariff option than any alternative tariff option.

Transitional considerations for the phase-out of the LFCs

There is an expectation that the phase-out of the LFCs will not increase overall prices to domestic consumers (except for usual price increases) as the cross-subsidies are unwound. The underlying assumption is that as the annual fixed price increases each year, as prescribed by s3A of the Amendment Regulations, the variable prices (i.e., consumption charges) will decrease.

However, as the cross-subsidies between low and standard users unwind, not all consumers will see an overall cost decrease. Broadly low users will pay more, and standard users will pay less. Avoiding price shock to residential consumers may require distributors to glide path the phase-out of the LFCs, resulting in variable prices changing at a different rate to expectations.

These guidelines recommend that distributors include a discussion of their planned phase-out of the LFCs in their pricing methodology and a transition plan in their pricing strategy to assure stakeholders that distributors are transitioning the phase-out in a considered fair and reasonable manner.

Other charges are not prescribed but have applied limitations

The LFC Regulations permit distributors to charge an unprescribed volumetric charge. However, there are limitations on how the distributor can apply those charges. The limitations mean that prices for residential connections that qualify for the LFCs are not cost-reflective for many distributors, resulting in those low-user consumers being cross-subsidised by standard consumers.

The extent of the cross-subsidisation, and the cost recovery from other pricing groups, can be based on social-economic equity considerations or other considerations, which differ significantly from distributor to distributor. These guidelines do not propose a standard approach to mitigating the extent of cross-subsidisation or cost-recovery resulting from complying with the LFC Regulations.

A summary of the limitations to residential pricing connections is included in Table 3.

Table 3. Summary of the limitations to pricing under the LFC Regulations

Section	Description
Section 9	Ensure that the average consumer[20] pays no more per year on a low fixed charge tariff option than on any alternative tariff option.
Section 10	Ensure that other charges under, and other terms and conditions of, the contracts to which low fixed charge tariff options relate are not unreasonably detrimental to the interests of low-use consumers.
Section 14	Ensure there is only one fixed charge for line function services to the home. And that the fixed charge does not exceed the amount prescribed by the 2021 Amendment Regulations (excluding GST). Distributors may only recover charges associated with the delivery of electricity to the home through the following: (i) one fixed charge; (ii) a variable charge or charges; and (iii) any fees for special services; and (iv) any fee payable for providing or reading any meter that the electricity distributor owns; and (v) any fee payable for providing any relay that the electricity distributor owns.
Section 15	Ensure that the variable charge or charges are such that the average consumer pays no more per year on a low fixed charge tariff than on any alternative tariff option.
Section 16	Ensure that the variable charges are not tiered or stepped, except to the extent permissible by subclause (2). And that fees for special services, rebates, or discounts are consistent with those offered to other consumers on any alternative tariff option.

3.4 Complying with the LFC Regulations

Distributors can comply with the requirements of the LFC Regulations by offering an LFC-compliant pricing option to —

- only those consumers who are eligible, or
- by offering an LFC-compliant pricing plan to a wider group of consumers.

Different approaches create different considerations. Where a distributor offers a low fixed charge plan and a standard plan, it increases the number of pricing plans offered and needs to be maintained; and is more complex to demonstrate compliance. Alternatively, where a distributor offers a low fixed charge plan to all

[20] An 'average consumer' is considered a consumer that consumes up to 9,000 kWh per annum in the Lower South region or 8,000 kWh elsewhere in New Zealand.

residential or wider groups of consumers, it is likely to result in less cost-reflective prices and is less complex to demonstrate compliance.

Appendix 1 of these guidelines are examples of techniques distributors might adopt to demonstrate compliance under the LFC regulations.

Each distributor must rationalise the trade-off between complexity and price efficiencies to choose the best fit option. The Authority recognised the complexity/efficiency trade-off in its Practice Note, as shown in Figure 12.

Figure 12. Trade-offs abound in the journey to reform distribution prices

> …there will always exist a tension between what we're advising each distributor to be cognisant of, and distributors applying their own judgment 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 structures that is more likely to achieve the intended customer response.[21]

These guidelines outline three approaches to setting LFC-compliant prices

These guidelines outline three approaches that distributors can take to set prices for residential connections and comply with the requirements of the LFC Regulations:

(i) Dual residential Plan
(ii) Single Residential Plan
(iii) Single General Plan.

> A Low Fixed Charge compliant pricing plan is one where the fixed charge is no more than the amount prescribed in the LFC Regulations, and if a Residential Standard plan is offered, total annual costs for the Low Fixed Charge plan need to be equivalent or less than the standard plan.

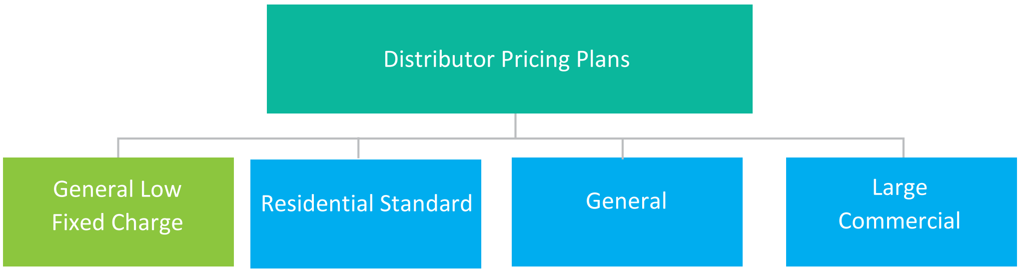
Note the light green shaded box in each of the following diagrams must be a low fixed charge plan.

Figure 13 illustrates where distributors offer a low fixed charge plan to a subset of residential consumers that meet the principal place of residence definition and select an LFC plan through their retailer.

[21] Supra n5, paragraph 76 on page 14.

Figure 13. Dual Residential Plan

A separate Residential LFC pricing plan is offered to qualifying residential consumers.

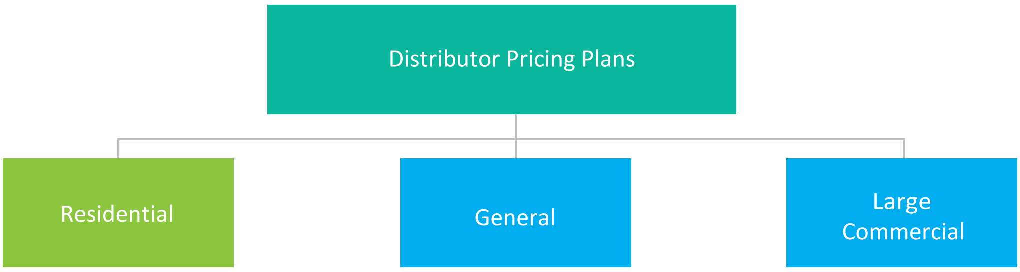


The approach is a dual residential plan structure. The Residential LFC plan will typically have a daily fixed charge prescribed by the Amendment Regulations and a higher variable, $/kWh, price than the Residential Standard plan.

Figure 14 illustrates where distributors offer one Residential pricing plan, a low fixed charge plan to all residential connections.

Figure 14. Single Residential Plan

All Residential connections are on an LFC pricing plan



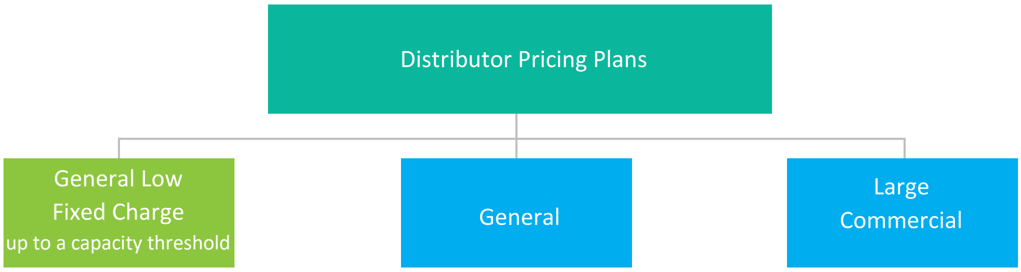
The approach is a single residential plan structure. All residential connections are charged the same fixed price component, no more than that prescribed by the Amendment Regulations, and $/kWh, a variable charge.

A variation of the approach in Figure 14 above restricts the Residential plan to qualifying Residential consumers only, i.e., for consumers' principal places of residence. All other residential connections (i.e., non-principal places of residence such as holiday homes) are charged based on the applicable general pricing plan.

Figure 15 illustrates where distributors offer a low fixed charge plan to a larger number of residential and non-residential connections below a specified capacity threshold and have gained an exemption. This approach is a single general plan structure.

Figure 15. Single General Plan

All General connections up to a capacity threshold are on an LFC pricing plan.



The distributor extends a low fixed charge plan to a wider group of small-capacity consumers, not just residential consumers.

Labelling pricing plans

A price plan need only be labelled as LFC if an alternative pricing plan is available. For example, in Figure 14 above, the Residential plan has an LFC, and no alternative plan is provided. Therefore, this price plan should be named "Residential". Conversely, in Figure *13*, a choice of plans is offered; an LFC or a standard residential plan. The plan or group names need to distinguish between them by clearly labelling the differentiation between the plans. For example:

- Residential – Low Fixed Charge (LFC)
- Residential – Standard.

3.5 Exemptions under the LFC Regulations

There are provisions in the LFC Regulations for distributors to apply for exemptions to the LFC Regulations. The Minister may grant exemptions under the conditions prescribed in regulation 26, as shown in Figure 16.

Figure 16. Exemption Provisions - Extract LFC Regulation 26

Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004

26 The Minister may grant exemptions

(1) The Minister may exempt an electricity retailer or electricity distributor, or an electricity retailer or electricity distributor in relation to a particular area or areas, from the application of any provision or provisions of these regulations if, in the opinion of the Minister,—

(a) any of the criteria in regulations 27 to 30[22] are satisfied; and

[22] Please note that regulation 30 only applied to retailers and was revoked on 1 April 2009, by regulation 16 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2008 (SR 2008/315).

(b) the electricity retailer or electricity distributor materially complies with the objective of section 172B[23] of the Act.

(2) The Minister may also exempt an electricity distributor, or an electricity distributor in relation to a particular area or areas, for the application of any provision or provisions of these regulations if—

(a) the distributor conveys less than 5 GWh per annum; and

(b) the distributor's lines are not connected directly, or indirectly through another distributor, to the national grid; and

(c) in the opinion of the Minister, the distributor would incur a significant or unreasonable cost in complying with the provision or provisions.

The exemptions that apply to distributors include:

- Regulation 27—exemption for closed or obsolete tariffs.
- Regulation 28 —exemption for remote areas with single lines serving few homes.
- Regulation 29 — exemption for homes served by dedicated transformers.
- Regulation 29A—exemption for homes with 3-phase, greater than 15 kVA supply, or both.

What is the benefit of applying for an exemption?

The benefit of a distributor holding an exemption under regulations 28, 29, or 29A of the LFC Regulations is that outlier residential connections can be excluded from the requirements for a low fixed charge, making it easier to set cost-reflective prices for these unique connections.

Specifically, an exemption under regulation 29A would enable a distributor to set a capacity threshold of 15 kVA for residential connections (the most common capacity for residential connections). Under the exemption, a distributor using subgroups (as discussed on page 24) could exclude residential connections with an installed capacity greater than 15 kVA from its LFC pricing subgroup, thereby simplifying their pricing structures.

How to apply for an exemption

Applications for an exemption must be made to the Minster in writing, under regulation 32.

3.6 Volume kWh charges

In the following section, we outline volumetric charges (dollars per kWh) commonly offered by distributors for small to medium capacity connections within metering categories 0, 1, and 2 as defined in the Code.

[23] Please note that section 178B of the Electricity Act 1992 was repealed, on 1 November 2010, by section 164(5) of the Electricity Industry Act 2010 (2010 No 1160.

These charges will apply to residential and small to medium commercial customers who comprise the residential and/or general pricing groups.

Time of use pricing

Time of use (ToU) is a variable price that changes based on the time of day electricity is consumed. At its simplest, how much a residential consumer pays for electricity will depend on when they use it.

Most ToU pricing plans will have a higher price during “peak demand” and lower prices during the “off-peak times”. There can be a “Shoulder” price which is the time leading into, or out of, the peak demand period. This price will be higher than the off-peak but lower than the peak.

Determining the peak, off-peak, and shoulder

Ideally, the time bands for peak, shoulder, and off-peak correspond to the actual times that peaks occur on the distributors’ network. Peaks can be identified using historical network averages; while less precise, this approach can be useful where a distributor lacks metering information or needs to smooth unusual network volatility. Distributors can use more precise approaches, such as low voltage metering and heat maps of their networks, to signal when and where the peaks and shoulder periods occur or are likely to occur.

Pricing can signal to consumers an existing or emerging constraint and encourage shifting load to off-peak periods, where it is effective. For example, where congestion is peaking one or two times a day, a ToU price can be used to encourage consumers to shift some of their load into off-peak times.

ToU is not by default considered cost-reflective

ToU pricing is effective where a distributor can demonstrate an existing or emerging constraint on the network driven by consumer behaviour. For example, a rapidly growing EV penetration causes a sharp and unsustained peak in an area of a distributor network.

ToU can be ‘inefficient” where prices are not reflective of existing or emerging network constraints. Further, ToU prices can have an unintended consequence of shifting the peaks instead of reducing demand during the peaks, as outlined in Figure 17.

Figure 17. Extract from the Authority’s Practice Note

> “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.”

Seasonal pricing

ToU pricing can be set for seasonal periods such as summer and winter. Seasonal variation is applied where loadings on a network have a distinct seasonal pattern. Currently, there is no standard definition for summer and winter periods.

Summer and Winter Periods

If distributors use summer and winter classifications in pricing plans, distributors are recommended to define summer and winter periods as:

- Summer period: 1 October to 30 April
- Winter period: 1 May to 30 September

Where a distributor needs to define an alternative season for a different purpose, avoid using the terms summer or winter. For example, a distributor might define an “irrigation season” using an alternative date range.

In all cases, seasonal date rages should include whole months.

3.7 Register Content Codes

Distributors should ensure that appropriate Authority-approved register content codes (or code groupings) are available for electricity retailers to apply to the volume price components offered. Distributors should look to align with existing register content codes before seeking approval for additional codes.

What are register content codes?

The meter equipment provider (MEP) records the register content codes against each meter register at a connection in the Registry. Distributors, traders, MEPs, and the Reconciliation Manager use the register content codes.

A new code must be added to the Registry when a distributor introduces a new volume price option and if an existing register content code does not cover the metering functionality requirement. The Authority must approve Register content codes. The registry functionality specification shows an approved list of register content codes available in SD-020 in the registry functionality specification.

What is a meter register?

The register content codes define the functionality of a meter register.

3.8 Metering configurations for Residential connections

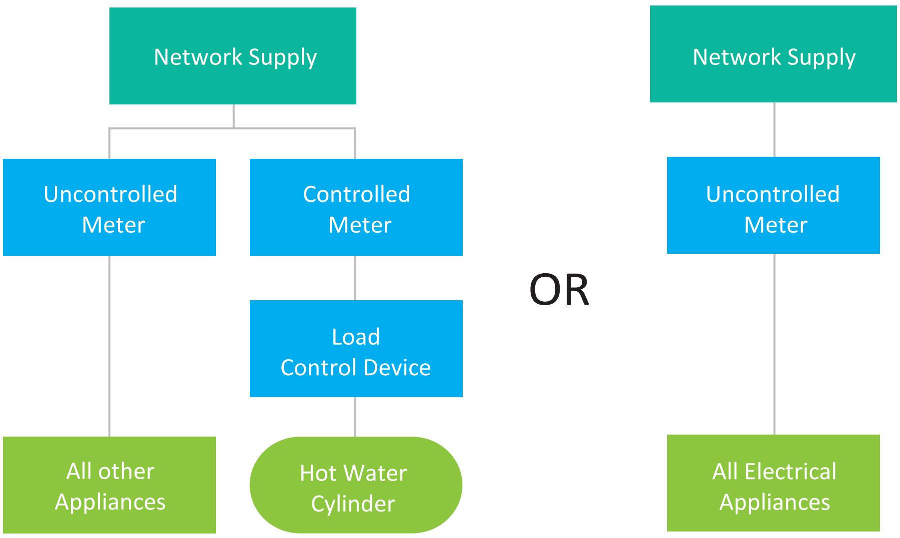
Uncontrolled

"Uncontrolled" supply (also referred to as "Anytime") is where the distributor does not have any ability to control the connection's load on that meter register, i.e., it is an uninterruptable supply. Uncontrolled supplies are common in situations where consumers have two meters.

- one meter, a continuous supply on a single meter register applicable where no load is controllable by the local distribution network on that register, is used to measure uncontrolled usage, and
- a second-meter, measures controlled usage with the applicable Register Content Code "UN".

The Controlled separate supply is typically used for hard-wired appliances such as hot water cylinders. The typical legacy meter setup for Uncontrolled supply is shown in Figure 18.

Figure 18. Uncontrolled supply (legacy meter setup)



An Uncontrolled supply will also be provided where consumers use an alternative fuel, such as piped natural gas or bottled LPG, to heat their hot water. In this instance, the Uncontrolled supply is likely to be the only type of supply provided to the connection.

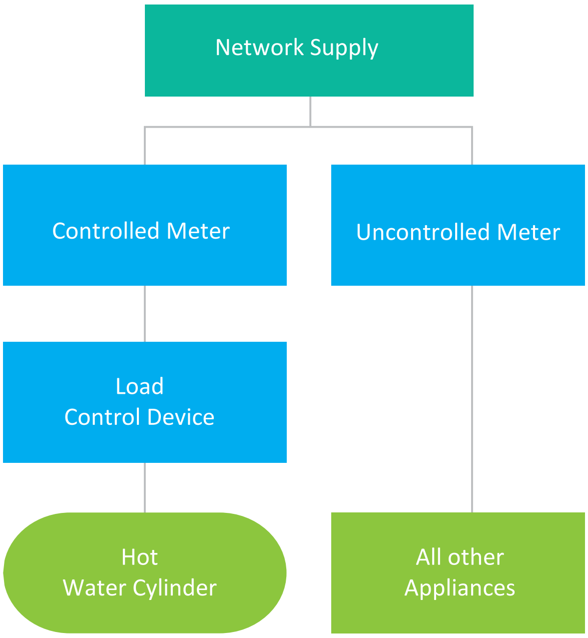
Controlled

A "Controlled" supply is where the distributor can periodically interrupt the supply to all electrical load connected to a particular meter (or meter register) at an installation. The Controlled supply meter, or meter register, would be connected to the controlled circuit with separately hard-wired appliances such as a hot water cylinder.

The difference between Controlled supplies and night plans (Night Boost and Night Only) is that the load control associated with a Controlled supply is not operated based on specific daily times. The typical legacy meter setup for Controlled supply is shown in Figure 19.

Option 2 specifies a minimum time (i.e., 4 hours) for which a storage water heater must be sized to support a reheat period (i.e., 4 hours) for which the element needs to be sized. The distributor has the flexibility to control load during both the normal residential morning and evening peaks and provide a 4-hour recovery/reheat period in between. The service level is described as "16" rather than 12 hours because, in practice, only two of the 4-hour load control blocks are used daily. No peak load management happens between 11 pm and 7 am.

Figure 19. Controlled supply (legacy meter setup)



Timing for Controlled Supply

Peak load control is usually operated according to service level targets (rather than a strict guarantee). There is a range of different timeframes used by distributors to control the load. The recommended options are in Table 4.

Table 4. Load control timing option for controlled price plans

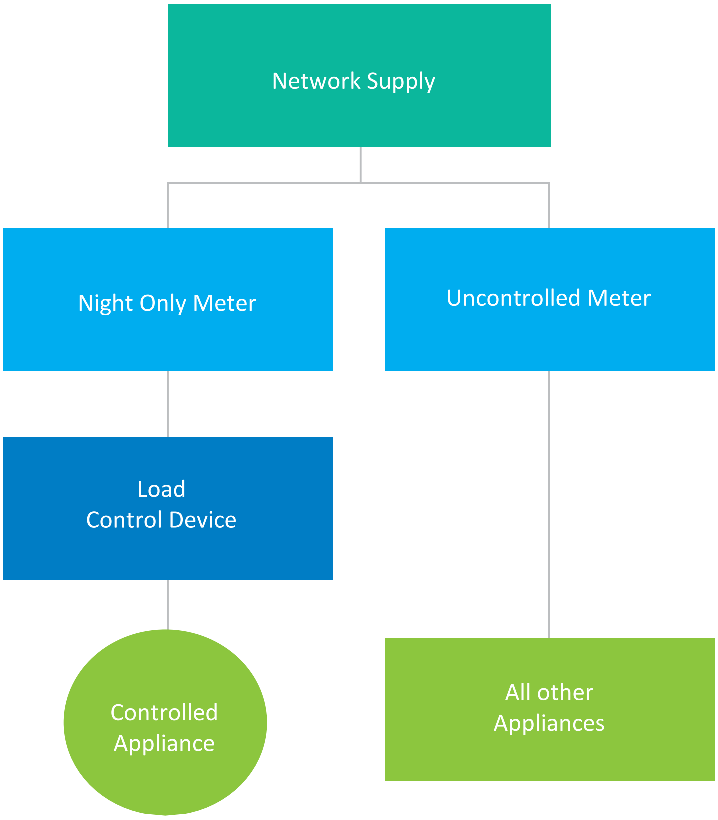
	Description	Price Component	Register Content Code
Option 1	Supply provided for a minimum of 18 hours per day *plus, uncontrolled meter*	Controlled 18 + Uncontrolled	CN18 + UN24
Option 2	Supply provided for a minimum of four hours in any eight hours *plus, uncontrolled meter*	Controlled 16 + Uncontrolled	CN16 + UN24
Option 3	Supply provided for a minimum of 20 hours per day *plus uncontrolled meter*	Controlled 20 + Uncontrolled	CN20 + UN24

Night Only

"Night Only" is a variation of Controlled supply in that the distributor controls the energy supply. However, Night Only and Night Boost have specific daily operating times that turn the supply to those meters on and off.

Night Only is a separately metered supply to permanently wired appliances, such as hot water cylinders or night store heaters, which are switched on at specific times. The typical legacy meter setup for Night Only supply is shown in Figure 20.

Figure 20. Night Only supply (legacy meter setup)



Night Only is supplied via a single meter register connected to permanently wired appliances that meet the distributor's criteria. All load on that meter register is switched "on" for the distributor's defined night period. For example, Applicable Register Content Code is "N08" and might be turned on from 11 pm to 7 am each night.

Timing for Night Only supply

For Night Only supply, the controlled load is typically turned on for eight hours, between 11:00 pm and 7:00 am, or ten hours between 9.00 pm and 7.00 am.

Night Boost

"Night Boost" is a variation of the Night Only supply. The energy supply to the specific permanently wired appliance/s, like Night Only, with an additional boost during the daytime.

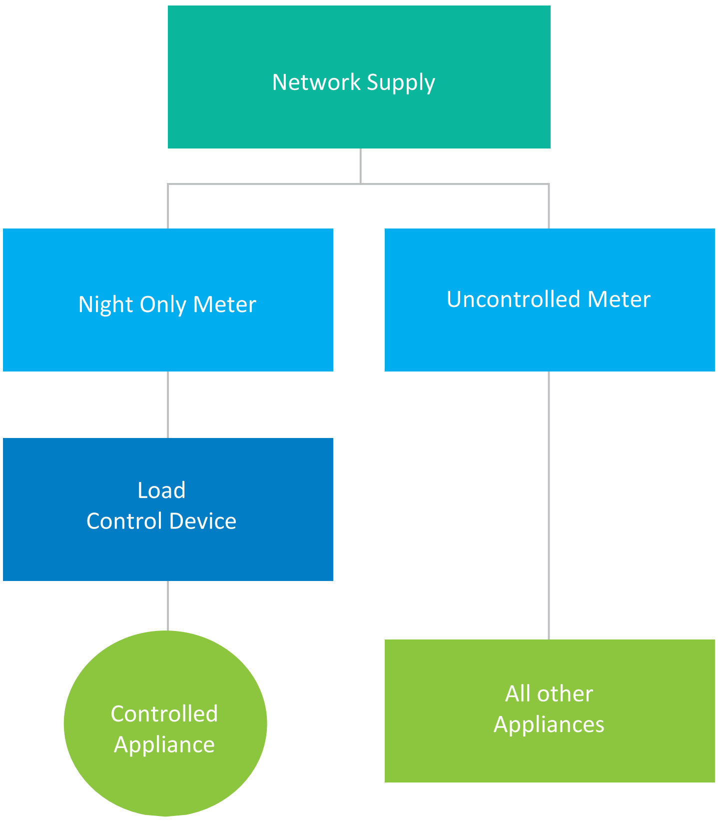
Night Boost is a separately metered supply to permanently wired appliances, such as hot water cylinders or night store heaters, switched on and off at specific times. Night Boost supply will be switched during specified " Night " periods[24] and for two to four hours during the "Day".

Night Boost is supplied by a single meter register connected to permanently wired appliances that meet the distributor's criteria for load control. All load on that meter register is switched on for the distributor's period defined Night and for two to four hours during the Day. Applicable Register Content Code is "NB," and the Period of Availability is consistent with Night Boost supply in the distributor's load control timeframes.

Timing for Night Boost supply

For Night Boost supply, the controlled load is turned on for the duration of the night period, eight hours from 11:00 pm to 7:00 am or ten hours from 9.00 pm to 7.00 am and is also turned on for a boost period of two to four hours during the day. The typical legacy meter setup for Night Boost supply is shown in Figure 21.

Figure 21. Night Boost supply (legacy meter setup)



[24] Night operation periods are discussed above. The signal is sent so appliances are switched on around 11pm and off around 7am.

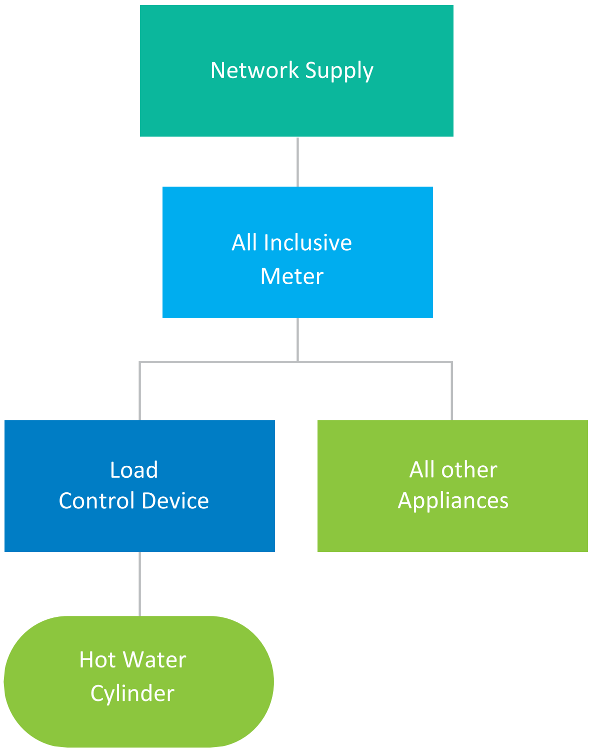
All Inclusive

An "All Inclusive" supply is a single meter register that measures controlled and uncontrolled usage at an installation. The All Inclusive setup results in the controlled and uncontrolled load being recorded on a single meter register. Therefore, it is impossible to determine the actual portion of uncontrolled and controlled load used by each connection. The typical legacy meter setup for All-Inclusive supply is shown in Figure 22.

If offered, the All Inclusive price is usually less than an Uncontrolled supply price, as the All Inclusive price assumes a portion of the energy consumed is subject to load control.

All Inclusive is a metered supply that allows the local distributor to control energy to permanently-wired appliances, such as hot water cylinders, and provide an uninterrupted energy supply to all other electrical appliances. A supply via a single meter register provides an uncontrolled supply to most appliances and a controlled supply to permanently-wired appliances that meet the distributor's load control criteria. Applicable Register Content codes are "IN18", "IN16," or "IN20", depending on the timing of load control.

Figure 22. All-Inclusive supply (legacy meter setup)



The recommended All Inclusive options are in Table 5.

Table 5. Load control timing options for all-inclusive price plans

	Description	Price Component	Register Content Code
Option 1	Supply provided for a minimum of 18 hours per day	All Inclusive 18	IN18
Option 2	Supply provided for a minimum of four hours in any eight hours period	All Inclusive 16	IN16
Option 3	Supply provided for a minimum of 20 hours per day	All Inclusive 20	IN20

Day and Night

Day and Night pricing is typically offered using a single element meter with dual registers that switches between the registers at predetermined times (set by the local distributor) each day. For the register switch to occur in legacy meters, a load control device or time clock must receive the distributor's signal to transfer the volume recording between the day and night register.

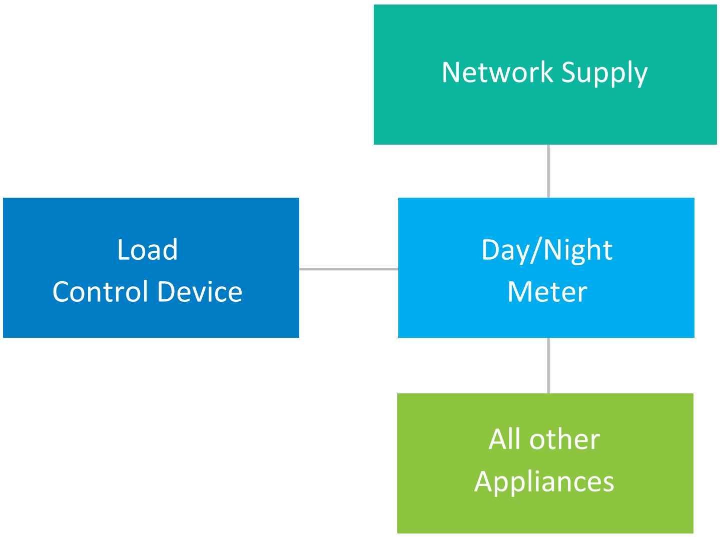
Advanced meters can record usage during the day and night periods. Legacy metering required a signal from a load control device to switch between the day and night register.

Specific appliances (e.g., hot water cylinders) are sometimes controlled to align with the Day and Night pricing plan, which means they will be turned on only at night. The typical legacy meter setup for Day and Night supply is shown in Figure *23*.

Most New Zealand distributors define Day hours as 7 am-11 pm (16 hours) and Night hours as 11 pm-7 am (8 hours). Several distributors use different timeframes to accommodate the significant loading levels at night. The most common other timeframes are Day hours of 7 am-9 pm and Night hours of 9 pm-7 am.

All appliances (controlled or otherwise) supplied during the distributor’s defined day period are recorded on one register, as shown in Figure *23*. During the night period is recorded on the other register. Alternatively, metering information from advanced meters can be accumulated to provide the day and night volumes. Applicable Register Content Codes are “D” and “N”.

Figure 23. Day and Night supply (legacy meter setup)



During the night period is recorded on the other register. Alternatively, metering information from advanced meters can be accumulated to provide the day and night volumes. Applicable Register Content Codes are “D” and “N”.

All appliances (controlled or otherwise) supplied during the distributor’s defined day period are recorded on one register. During the night period is recorded on the other register. Alternatively, metering information from advanced meters can be accumulated to provide the day and night volumes. Applicable Register Content Codes are “D” and “N”.

Where a Day and Night option is available, Distributors should provide one of the following two options listed in Table 6.

Table 6. Description of timing options for day and night supply

Option	Description
Option 1	Day period: 7am-11pm (16 hours) Night period: 11pm-7am (8 hours)
Option 2	Day period: 7am-9pm (14 hours) Night period: 9pm-7am (10 hours)

3.9 Volume-based charges for Small Scale Distributed Generation

The Distributed Generation Pricing Principles (DGPP) are in Schedule 6.4 of the Code. The principles provide that distributed generators are not charged more than their incremental connection cost.

In May 2016, the Authority published a *Review of the Pricing Principles for Distributed Generation*. The paper proposed to remove the Pricing Principles for Distributed Generation.

Several distributors charge a volume price for energy injected into their network specified as $/kWh.

Many distributors specify a zero price for volume injected into the network, reinforcing that they require retailers to provide both load (X for extraction) and generation (I for injection) volumes as part of the billing process.

Some retailers utilise Code provision 15.3 to gift energy generated by their customers to the wholesale market, therefore not submitting the volume generated for reconciliation purposes. These code provisions do not cover the provision of the volume generated from retailers to distributors.

If charges are levied for volumes generated, the price should be specified as $/kWh for volume injected. Alternatively, if charges are levied for connected capacity, the price should be specified as $/kVA connected. Cost-reflectivity principles suggest that the basis of levies charged should reflect the costs to serve small-scale distributed generation.

4. General Connection Group

4. General Connection Group

The General group can be applied in two ways:

i. where there is no differentiation between residential and non-residential consumers, the term includes all connections up to the specified Large Commercial group, or

ii. to describe consumers with an unspecified connection type, i.e., not identified as Residential or as a specialty group (e.g., Irrigation, Unmetered or Temporary Supplies) up to the specified threshold for the Large Commercial group.

Using the term "General" avoids the need to refer to a group of customers as "non-residential" or use the label "small commercial" or "small business" for connections that are not necessarily commercial.

A distributor need not have specific groups for connection types, including Unmetered, Temporary supply, or Irrigation connections. These connections will be included in a General group if not otherwise specified. As with the residential connection group, if there are subgroups within the general category to reflect specific cost characteristics such as high cost/low-cost area categories, these distinctions are considered non-standard. Non-standard terms should be noted in the distributor's pricing methodology and justify the non-standard approach.

4.1 The capacity threshold between General group and Large Commercial

Distributors must define an upper limit of installed capacity (typically based on fusing) for the General group. Above the threshold specified, a connection would be included in the Large Commercial group. The upper limit of the General group is the lower limit of the Large Commercial group.

The metering requirements of the Code provide a natural demarcation between General and Large Commercial consumers. The Code states that Metering Category 3 and above is required for all consumers with a capacity greater than 500 Amps. Therefore, consumers with a capacity greater than 500 Amps will be subject to real and reactive half-hourly metering, enabling more pricing options for distributors than those without half-hourly metering. A three-phase 500 Amp supply is commonly referred to as 345 kVA (an approximation to the calculation of 500 amps at 400V 3 phase of 346.4 kVA).

Distributors who wish to have a lower capacity threshold between the General and Large Commercial groups can include it in their network connection standards and pricing documentation. Consumers above the specified capacity level must install half-hourly metering in this instance.

If the distributor required half-hourly metering for consumers with a capacity greater than 150kVA, for all connections 3 phase 250Amps or larger, the threshold between the General group and the Large Commercial group would be set at 150kVA.

4.2 General pricing components

Retailers will likely submit non-half-hour data for consumers in the General pricing group. It is common for retailers to provide consumption data to distributors (where applicable) in a monthly format (EIEP1 files) regardless of whether advanced (i.e., HHR) or legacy metering (i.e., NHH) is installed. Compared to consumers in the Large Commercial group, this limits the current pricing options available to distributors.

Therefore, the price components used for consumers in the General group will typically be the simple two-part pricing structure, with fixed $/day and volume $/kWh, pricing components like the Residential group.

However, the metering does not rule out the use of capacity charges. These could be specified as $/kVA of installed capacity based on the fuse size provided for the connection or the transformer size where a dedicated transformer is installed.

Some distributors also charge profiled demand charges to General consumers. Capacity and demand prices are discussed in more detail in the section on Large Commercial consumers in section 7.

4.3 Current price structures implemented by distributors

Analysis has been performed on the pricing structures of the 29 New Zealand distributors for General and Large Commercial customers. There is a large variability in how distributors group connections and specify capacity thresholds for pricing plans.

The analysis showed around 151 price categories, of which 130, or 86%, were defined differently.

Alignment in this area would allow distributors to retain their preferred level of granularity within their existing structures while significantly reducing the number of unique price category definitions.

Although not directing a one-size-fits-all approach, these Guidelines highlight some standard capacity bands consistent with the voltage assumptions and fuses used in New Zealand. The aim is for distributors to describe capacity in a standard way and for similar-sized connections to be grouped into price plans more consistently.

4.1 General capacity categories

The general group may be divided into two or more categories according to the capacity of connections. Table 7 provides proposed definitions from the 130 different price category definitions across 29 distributors' pricing schedules. While not a complete list, it covers most existing definitions.

This definition promotes the rationalisation of the small capacity price categories across distributors.

Table 7. Proposed lower and upper price bands - General consumers

Description of Fusing	Phases	Amps	Volts	Calculated kVA	Lower Limit (kVA)	Upper Limit (kVA)
Single Phase 20 Amps Single Phase 30 Amps Two Phase 20 Amps	1 1 2	20 32 20	230 230 400	4.6 7.4 9.3	0	10
Three Phase 20 Amps Single Phase 60 Amps Two Phase 30 Amps	3 1 2	20 63 32	400 230 400	13.9 14.5 14.9	11	15
Three Phase 30 Amps Two Phase 60 Amps	3 2	32 63	400 400	22.2 29.4	16	30
Three Phase 60 Amps	3	63	400	43.6	31	50
Three Phase 100 Amps	3	100	400	69.3	51	70
Three Phase 150 Amps Three Phase 160 Amps Three Phase 200 Amps	3 3 3	150 160 200	400 400 400	103.9 110.9 138.6	71	150
Three Phase 250 Amps Three Phase 300 Amps	3 3	250 300	400 400	173.2 207.8	151	210
Three Phase 400 Amps Three phase 500 Amps	3 3	400 500	400 400	277.1 346.4	211	350

Amalgamation has been achieved by incorporating lower capacity price categories of “Unmetered,” “1 kVA,” and “5 kVA” into a “0-10 kVA” band. Table 7 sets standardised kVA values and lower and upper limits for pricing categories. Note that fusing for 32 and 63 Amps is commonly referred to as 30 and 60 Amps. The common description has been used in the table, but the calculation of kVA is based on 32 and 63 Amps.

It is not proposed that distributors change the structure of their price categories to match Table 7. Rather, utilise the lower and upper limits to align the specification of their existing price category definitions. Limits will better align price category definitions while allowing distributors flexibility to add, amalgamate or remove existing price categories as they move to a standardised approach.

For example, a distributor might wish to define only three price categories using the definitions above and label these as:

- 0 – 15 kVA
- 16 – 150 kVA
- 151 – 350 kVA

For example, a distributor currently specifying load groups as “0-15 kVA”, “16-30 kVA”, “31-45 kVA,” & “45-70 kVA” should redefine two of their load groups as “31-50 kVA” & “51-70 kVA”.

For Example, a distributor currently specifying “<= 69 kVA” & “>69 kVA” could be redefined as “0-70 kVA” & “>70 kVA”.

The selected limits are specified so whole numbers can be used, and a simple and unambiguous labelling system is adopted. A category labelled 16 - 150 kVA would include all connections >16 kVA and <=150 kVA.

5. Large Commercial

5. Large Commercial

Many pricing components can be used when connections have meters reporting kWh and kVArh on a half-hourly basis.

The wide range of prices has led to considerable variance and complexity in distributors' prices for Large Commercial customers.

Large commercial consumers are distinguishable by how they utilise the distribution network. These consumers tend to be large connections with high utilisation of their installed capacity. A large commercial consumer can be connected to the low voltage network and larger than a nominated threshold, e.g., ≥350kVA, or connected at high voltage (i.e., 11kV and above).

The term "large' is highly subjective and differs between distributors. The nominated threshold is subjective and relative to the characteristics of the network and can be set lower, e.g., >150kVA, >110kV, or >69kVA, to suit the network characteristics.

The objective of these guidelines is to:

- Standardise terminology used by distributors when describing these more complex price components
- Encourage standardisation of price components used by distributors.

The first step is to reduce the apparent complexity and differences between distributors' price structures, and the second is to reduce the actual complexity and differences.

This pricing group applies to larger commercial connections where more sophisticated metering is installed, allowing for a range of pricing approaches that better reflect costs and services provided. Specifically, the metering records real (kWh) and reactive (kVArh) energy usage on a half-hour basis.

This pricing group normally applies for connections with metering categories 3, 4, or 5, as defined in the Code. (Appendix 3 has a summary of the metering categories). These connections are typically low voltage connections with a capacity greater than 350kVA but also apply to all high voltage connections (11kV and above).

A distributor may set a threshold lower than 350kVA for this pricing group, such as 150 kVA, and require the appropriate half-hour interval metering for these customers. A lower limit than 350kVA has been specified category 2 metering using the "HHR" option would be an alternative to the metering category 3, 4, or 5.

As the Large Commercial group may include large consumers, distributors may offer individual, or non-standard pricing, to some consumers.

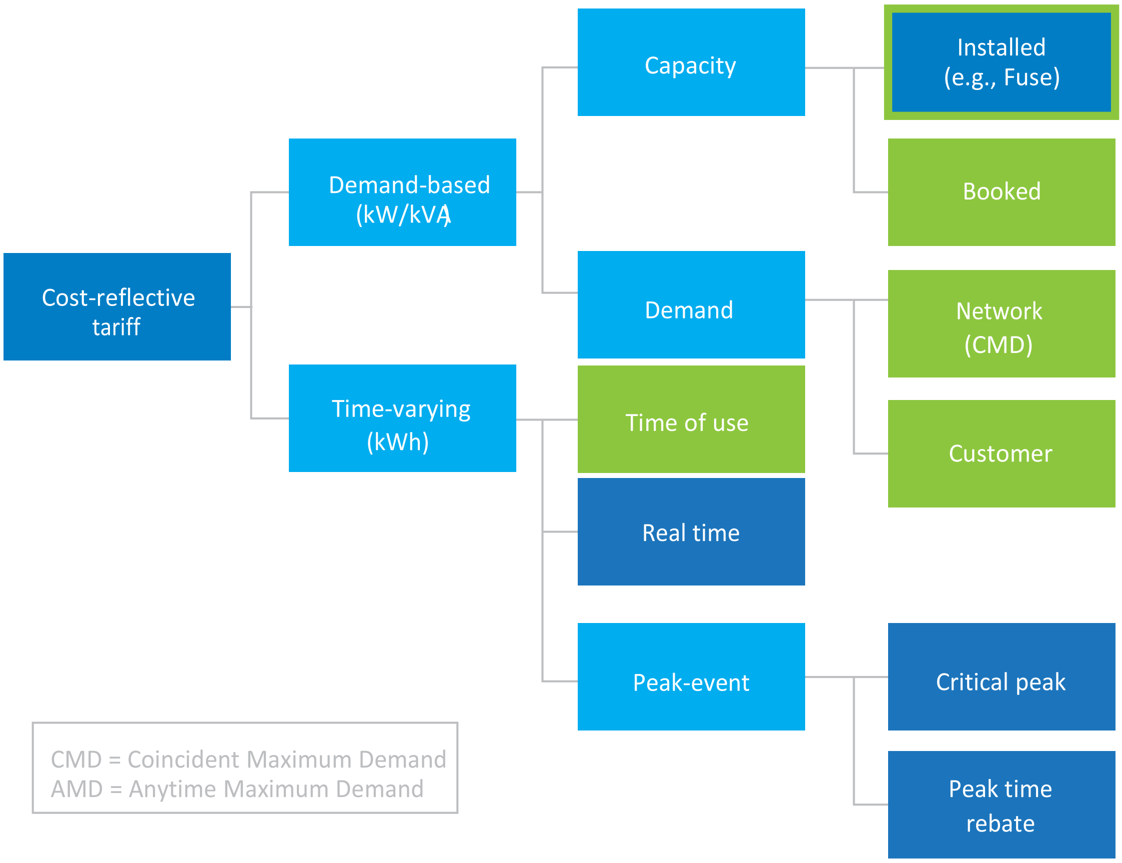
5.1 Large Commercial price components

A 2016 ENA discussion paper on new pricing options reviews price components available to distributors when half-hourly data is available. Some of these pricing components are already used by distributors for Large Commercial customers.

The consultation paper provides information on:

- Time of Use pricing (kWh pricing, which varies depending on the nominated period)
- Capacity pricing (pricing based on the installed or nominated capacity of connection)
- Demand pricing (pricing based on the demand of the consumer). These approaches are summarised in Figure 24.

Figure 24. Pricing options (from New Pricing Options for Electricity Distributors)



The ENAs New Pricing Options for Electricity Distributors figure illustrates the pricing options available where half-hourly data is present. While the future pricing paper is considering price options primarily for Residential consumers, some price options stated are currently used by distributors for Large Commercial consumers.

5.2 Time-of-use consumption charging

The Time of Use (ToU) pricing method refers to prices that vary based on the time of consumption (or use). ToU prices are not a new concept for electricity consumers as Day/Night prices and Night Only and Night Boost prices are currently available for Residential consumers.

ToU prices for Large Commercial consumers rely on half-hourly metering (and data provision) to capture kWh quantities for each pricing period. Distributors may choose to signal peak periods in their network load by applying differing prices across periods. For example, a distributor with a peak period between 5 pm and 9 pm might implement a higher kWh ToU price. The price differential incentives consumers to shift consumption outside the peak period.

Currently, few distributors apply significant ToU volume pricing to Large Commercial consumers. Distributors currently use Demand pricing to reflect those peak demands on their networks are a significant driver of costs.

5.3 Fixed Daily charge

Distributors often include a fixed daily charge ($/day) for each connection with other pricing components. Historically the fixed charge has been minor compared to other components (i.e., variable charges) and may reflect the cost associated with managing a connection, determining quantities, and applying prices.

Rather than including the cost within capacity or demand pricing, applying a fixed charge avoids over-allocating administration costs to larger consumers.

Fixed daily charges are also often used for specific items of dedicated equipment, e.g., transformer charges.

Where there is no need to signal economic costs of network use, the Authority considers a fixed daily charge an efficient cost recovery method.[25] Throughout its Practice Note, the Authority supports shifting cost recovery to higher fixed charge components, where it is efficient, as shown in Figure 25.

Figure 25. Reform for some networks might simply mean moving to higher fixed charges

> "We acknowledge that for distributors that do not face congestion now (and don't expect to soon), reform may simply mean moving to higher fixed charges and reducing variable charges, once LFC regulations allow."[26]

[25] Supra n5, Table 3 at page 13
[26] Supra n5, paragraph 80 at page 14.

5.4 Capacity charges

Capacity charges are typically fixed and unavoidable in the short term. These charges do not signal to reduce the usage of the network, at least not in the short term, and are therefore well suited for recovering costs that will not change if a customer's usage changes.

There are common sub-types of capacity charges[27]:

- Installed capacity charges ($/kVA/day or $/kVA.KM/day)
- Nominated capacity charges ($/kVA/day)
- Category capacity charges ($/day specified for each category)

5.5 Installed capacity charges

Installed capacity charges are based on physical equipment (typically a fuse or transformer) capacity. Installed capacity charges are easy to administer and do not require specific metering technology, so they can be applied to smaller sites. They can also be structured to reflect the delivery distance using a $/kVA-km per day price.

The physical capacity is the:

- Fuse capacity, where the customer is supplied by a transformer that also supplies other customers
- Transformer nameplate capacity, where the customer is supplied by a transformer dedicated to that customer (i.e., it does not supply other customers).

5.6 Nominated capacity charges

Nominated capacity charges (like "booked capacity") are an alternative to installed capacity charges and are based on a capacity the customer nominates and agrees not to exceed. These charges can be used where a customer's connection capacity is not limited by distributor-provided equipment. And often occurs when the customer connects to the network at high voltage (11kV or higher). Nominated capacity charges are either:

- Complemented by an excess demand price charged when a customer exceeds their nominated capacity; providing an incentive for the customer to nominate an appropriate capacity value, or
- Automatically increased when a customer exceeds their previous nominated capacity.

[27] Some distributors currently employ a 'capacity' price that is based on a customer's measured demand over a certain period. This type of price (which we call a customer-peak demand price) is discussed in the demand prices section below.

Installed or nominated capacity approaches avoid the averaging within categories, and the potential rate shock should connections move between categories.

Note that distributors cannot set an excess demand price as a "penalty" price and should not describe it as a penalty (there are legal restrictions around the application of "penalties"). When setting the excess demand price, distributors should consider the increased costs of providing additional "unplanned" capacity due to consumers exceeding their nominated capacity.

Because of the requirement to meter demand to ensure a customer does not exceed their nominated capacity, a ToU meter capable of measuring kWh and at least one kVAh and kVArh at half-hour intervals is required for nominated capacity prices.

A nominated capacity price is based on a capacity nominated by the customer and approved by the distributor. The capacity chosen can be less than the physical capacity installed. The distributor does not imply or guarantee (by applying an excess demand price or otherwise) the availability of increased nominated capacity.

5.7 Category capacity charges

As an alternative to installed capacity charging, some distributors establish set capacity categories (load groups) and assign connections to these categories (like the approach used for connection in the General group).

The categories should be described similarly to the general connection capacity categories described above where this option is utilised. In this case, the fuse size and/or dedicated transformer size may be used to assign connections to the appropriate category. If dedicated to the consumer's connection, common fusing and associated transformer sizes are shown in Table 8.

Table 8. Proposed lower and upper bands for Large Commercial Consumers

Description of Fusing	Actual kVA	Typical Transformer capacity	Lower Limit (kVA)	Upper Limit (kVA)
Three phase 250 Amps[28]	173	150 or 200	151	210
Three phase 300 Amps	208	200	151	210
Three phase 400 Amps	277	300	211	350
Three phase 500 Amps	346	300 or 500	211	350
Three phase 750 Amps	520	500	351	550
Three phase 1,000 Amps	693	750	551	750
Three phase 1,250 Amps	866	1,000	751	1,000
Three phase 1,500 Amps	1,039	1,250	1,001	1,500

For example, a distributor might wish to define only three price categories using the breakpoints above 350 kVA and label these as:

- 351 – 750 kVA
- 751 – 1,000 kVA
- >1,000 kVA.

The decision as to where to set the lower band and breakpoint for connections is driven by operational considerations and is the distributor's choice.

> *With the selected standard breakpoints, the convention of specifying the upper bound as a whole number provides a simple and unambiguous labelling system. Technically, a category labelled 351 - 750 kVA would include all connections greater than 350 kVA and less than or equal to 750 kVA.*
>
> *The 351 kVA (Three Phase 750 Amps), breakpoint, defines the point where category 3 half hour interval metering is required under the Code.*

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[28] Fusing and transformer capacities of less than 3 Phase 750 Amps have been included in Table *8* as some distributors implement a lower threshold between General and Large Commercial pricing than 3 Phase 750 Amps.

5.8 Demand charges

Demand charges are prices charged against a customer's actual maximum usage over a certain period (the "measurement period"). The measurement period is when the customer's chargeable quantity is measured and the "charging period" is when the customer's chargeable quantity is charged.

Demand charges signal to the customer the costs of their maximum usage and provide incentives to reduce maximum usage. Key parameters can categorise a variety of demand charges currently used by distributors:

- The length of the period over which chargeable quantities are measured and applied
- The times (of the day, week, year) when chargeable quantities are measured
- The notification of times when chargeable quantities are measured.

These key parameters are outlined in further detail below.

5.9 Static demand measurement

The chargeable demand is measured over a period and then applied as a fixed "static" quantity over a charging period for static demand measurement. The measurement period occurs before the charging period and covers either a full year or the peak load season, usually winter. The charging period usually covers an entire year. A common approach is to use a calendar year (ending 31 December) as the measurement period and the following financial year (1 April to 31 March) as the charging period.

The chargeable quantity remains constant over the charging period. The distributor usually calculates the chargeable quantity and enters the value into the Registry.

Example

The demand price is a daily price applied to the consumer's highest kVA demand during the pricing year immediately preceding the current pricing year. It is fixed for the current pricing year. Rather than a single highest half-hour, an average of the highest [6 or 12] measured demands can be used.

5.10 Dynamic demand measurement

For dynamic demand measurement, the chargeable demand is measured within a month and used as the chargeable quantity for that month (it is "dynamic" in that it changes each month).

Example

The demand price is a daily price applied to the average of each consumer's 12 highest kVA demands during the month.

Static and dynamic demand measurements can be applied against a customer's peak demand or contribution to the network's peak demand. These are described below.

A drawback of this approach is that it charges for and encourages a response in months where a customer’s load might be cyclically (or seasonally) low and not driving costs.

5.11 Customer-peak demand charges

A customer-peak demand charge (also known as an anytime maximum demand price) is based on the customer’s maximum demand, often within a specific period (for example, 7 am to 9 pm on working weekdays). If there is no specific period, the charge is described as an “anytime maximum demand” charge. The chargeable demand can be the single highest half-hour demand or the average of the highest six or 12 half-hour demands.

5.12 Network-peak demand charges

A network-peak demand charge is based on the customer’s contribution to network peaks when the network is busiest. Peak charges are more commonly used with static demand charging as network peaks are seasonal. The chargeable quantity is measured only during specific times (network peak period).

It can be taken as the single highest half-hour demand within the network peak, the average of the highest six or 12 half-hour demands during the network peak, or the average of all half-hour demands within the network peak period.

Network peak periods

A pre-defined network peak period is notified to customers before the start of the pricing year. The period may be limited to specified hours throughout the day, days of the week, or months of the year. Most distributors use pre-defined periods for their network-peak demand prices.

For example, a pre-defined network peak period is 7 am to 11 am and 5 pm to 9 pm on weekdays. Customers are aware of the pre-defined periods and can plan their activities accordingly.

A notified network peak period is notified at the time the peaks occur. Network peaks are often weather responsive, and this approach allows the chargeable period to be accurately aligned with network peak loadings, making it more cost-reflective.

Distributors determine when peaks occur based on loading levels and other attributes, such as the hot water load control. This approach relies on active notification methods which allow customers to respond. Examples include ripple signalling, text, email, smartphone application alerts, and web services. With half-hour metering resolution, the chargeable network peak period is appropriately restricted to the whole real-time half hours that fall within the signalled peak period.

A retrospective network peak period is determined after it has occurred. While this accurately captures the actual network peaks, it is usually not possible for customers to anticipate when these occur so they can respond at the time. The timing of network peaks can be very volatile where networks carry out load management activities to flatten load.

Under the predefined approach, the notified network peak period approach avoids diluting the price incentive over a longer averaging period. It avoids encouraging a customer response when peaks are not occurring (for example, on warm winter days). However, it is more difficult to notify customers so that they respond in real-time.

Providing a defined period when network peak periods can be notified will reduce uncertainty. For example, the peak period season could be defined as May to August, working weekdays between 7 am and 9 pm. Customers preferring a fixed approach can then plan their activities accordingly.

Recommended demand prices

Customer peak demand charging provides a useful reflection of the size of load-dependent assets closer to the customer and carries a higher degree of customer understanding and acceptance. Further, under the TPM, the residual charges are allocated based on maximum gross demand at each connection location, i.e., a coincident approach is used to measure AMD across GXPs that are in the same location.[29]

Network peak demand charging provides a useful reflection of the often greater upstream costs of the shared network.

Network peak demand charging is particularly useful for interconnected networks with significant shared assets, with load growth requiring these assets to be upgraded.

Distributors should consider their specific situation and adopt a combination of approaches that best suits the circumstances.

[29] TPM Decisions Paper, paragraph 12.5 at page 86.

Static and dynamic demand charging are both commonly used by distributors. Static quantities may be more cost-reflective, require a greater administration level, and might not be appropriate for some distributors. Both static and dynamic demand prices are acceptable.

The most common approach is to have pre-defined periods during which the prices apply. It provides the best opportunity for consumers to respond to the price signal but is not as cost reflective as signalling network peaks when they occur. The Authority believes that distributors' prices must link to congestion, as shown in Figure 26.

Static demand prices may require processes to review values charged for new connections or a connection that has changed use (e.g., a new customer at a connection).

Figure 26. The link between congestion and price signals is necessary

> "Without a link between congestion and price signals (current or forecasted), a distributor risks reducing the welfare of customers, encouraging actions (defection, reducing consumption) that it does not desire, distorting behaviour unnecessarily, and causing harm to all parties."[30]

Using notified peak periods and a pre-defined limited period during which peaks can occur significantly enhances cost reflectivity. It should be considered where the magnitude of the costs is significant enough to warrant the added complexity. This approach may become more attractive as technology enables easier measurement and communication of network peak periods.

Retrospective network peaks provide limited opportunity for customers to respond. Accordingly, prices charged using retrospective network peaks are not recommended.

[30] Supra n5, paragraph 97 at page 17.

6. Individual Pricing Group

6. Individual Pricing Group

Individually Priced (also referred to as "non-standard") is a term used to identify customers whose circumstances mean the distributors' standard approach to pricing does not meet their needs. These tend to be large and unique customers who require pricing approaches tailored to their circumstances.

There is no one pricing approach for these customers

Pricing approaches for individual customers are customised to meet their unique needs. Common approaches include:

- capacity charges for customers with dedicated assets or on the high voltage network—reflecting the network capacity available to them, and usually requested at the time of connection, irrelevant of the utilisation of that capacity,'
- capacity or ToU charges for customers on shared assets—these customers will usually be on a shared transformer, and
- demand charges for customers on shared assets connected to a constrained network are more likely to be price elastic and respond to sent pricing signals.

Consumption charges (e.g., kWh) are less common for customers in the individual pricing group, particularly when that customer is a large industrial. This is because consumption charges are not considered cost-reflective for these customers because the cost to serve does not change based on the volume they consume. Rather, the costs are driven by their connection size, when and how they use it (i.e., do they utilise their load during peak or off-peak times), and is their load driving the peak.

Follow good pricing practices

Distributors must follow no one approach when pricing for customers in the individual pricing group. As with other pricing approaches, distributors should follow good pricing practices by applying the Authority's Pricing Principles and Practice Note.

Conveyance only agreements

Consumers in the Individually Price group might also have a supply agreement directly with a distributor, known as a "conveyance only"[31] [32] or "direct customer" agreement. Clause 3 of the DDA allows for the provision of conveyance-only arrangements.

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[31] Under Part 12A of the Code all distributors must have a default distributor agreement (DDA). Distributors must comply with Schedule 12A.1, 12A.2 and 12A.4. Those distributors that owns or operate an embedded network must also comply with Schedule 12.3 of the Code.

[32] Clause 33.2 of the DDA stipulates that "Conveyance Only" means a situation in which the Trader contracts with the Customer for the supply of electricity only in relation to an ICP and the Distributor does not provide Distribution Services tot eh Trader in respect of that ICP.

7. Speciality Pricing Groups

7. Speciality Pricing Groups

7.1 Unmetered Load

Normally load is required to be metered. Metering ensures that all load is accurately reconciled for the wholesale market and charged to those who used it. However, there is a limited range of circumstances where the load is not required to be metered.

Unmetered load is defined in Part 1 of the Code as—

> *Unmetered load means electricity consumed that is not directly recorded using a meter, but is calculated or estimated in accordance with this Code, and includes shared unmetered load and distributed unmetered load*

The Authority has issued guidelines on managing unmetered load.

"Guidelines on Unmetered Load Management" v2.1 is available on the Authority website[33] and states:

> *There are three types of unmetered load: standard unmetered load, and two special types (shared unmetered load and distributed unmetered load), each having specific management requirements.*

The Authority's unmetered load management guidelines assist participants to manage and submit unmetered load volume to the energy market for reconciliation.

The unmetered load guidelines state that an unmetered load may be the only load at an ICP or may co-exist with metered loads at the ICP.[34]

Standard Unmetered Load

Standard unmetered load is not defined in the Code but is explained in the Authority's guidelines[35] on unmetered load as:

> *Standard unmetered load is unmetered load at a single point of connection that is distributed across only one ICP, and benefits only that one point of connection.*

Individual connections

Because of its limited consumption, there is a situation where metering is not required for load at a single connection. Part 10 of the Code[36] provides for a connection to be unmetered if it is expected that the load, in any rolling 12-month period, to be no greater than:

> *(i) 3,000 kWh; or*

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[33] https://www.ea.govt.nz/dmsdocument/8578 – available on request from the Electricity Authority.

[34] EA Guidelines on Unmetered load version 2.1 page 1 646902-3

[35] EA Guidelines on Unmetered load version 2.1 page 7 646902-3 there are three types of unmetered load: standard unmetered load and two special types (shared unmetered load and distributed unmetered load).

[36] http://www.ea.govt.nz/dmsdocument/8601

(ii) 6,000 kWh if the load is of a predictable load of a type approved and published by the authority.

The approved types of loads which may be unmetered up to 6,000kWh are:

- amenity lighting (including billboards, advertising hoardings, bus shelters, phone booths, school signs, and public conveniences)
- street lighting (excluding street lighting that is distributed unmetered load)
- right of way lighting
- under veranda lighting
- floodlighting where the usage of the lights is regular, i.e., daily such as traffic lights
- radio transmitters/receivers and communications cabinets
- distribution equipment
- sewage and stormwater pumps.

The categories above are permitted to be unmetered connections, provided their daily use can be predicted. It must be known when they will be used and for how long. Designating a connection as amenity lighting does not ensure it will fulfil the requirements for the unmetered load as set out above.

A connection with an unpredictable load expected to use more than 3,000kWh per annum must be metered. It would be charged according to a distributor’s relevant metered load price category code.

A standard unmetered load has a variety of end uses and a range of characteristics. While it is possible to segment sites into categories and establish charges on an individual basis, it is recommended that all standard unmetered load on individual connections are charged on the following basis:

- For lighting - a combination of fixed and variable prices where the fixed is $/fixture/day and the variable is $/kWh. The variable component would be calculated based on a night hours table or actual light “burn” hours from a data recorder.

- Other loads - a combination of fixed and variable prices where the fixed is $/day and the variable $/kWh based on a calculation established by reference to the load and expected operation time of the fixture.

For lighting operating only during the night, the night hours table can offer reasonable accuracy on total monthly consumption. Other unmetered loads can be accurately calculated based on the information supplied at the time of connection.

No individual connection (co-exists with a metered load on an ICP)

An unmetered co-existing load is where an unmetered load is part of a metered connection. These are typically under-veranda lighting where the load is not included within the metered load of the shop or other premises. Where possible and subject to any billing system limitations, this load should also be priced on the same basis as individually connected unmetered load.

Distributed Unmetered Load

Distributed unmetered load is defined in the Code as—

> *Distributed unmetered load means unmetered load with a single profile supplied to a single customer across more than 1 point of connection*

The most significant unmetered loads are streetlights operated by local authorities.
The Authority estimates that around 1% of the total electricity consumed in New Zealand is used for streetlights, making it the most significant component of the unmetered load.

Local authority streetlights fall within the definition of distributed unmetered load. Other significant local entities with lights connected to Distributors' streetlight circuits operate and charge similarly to council streetlights. LED lighting is now available and installed as an alternative to traditional streetlights. LED lighting is more energy-efficient (less kW to provide the same light output) and has lower maintenance costs due to the extended life of the light source. And other emerging technologies continue to change how communities' needs are met. These include solar-powered lights, motion sensors for lights, and smart controlled dimming.

A sizeable portion of a distributor's cost of providing service to distributed unmetered load is fixed. Other factors relevant to the basis and level of charges are when streetlights are operating at times:

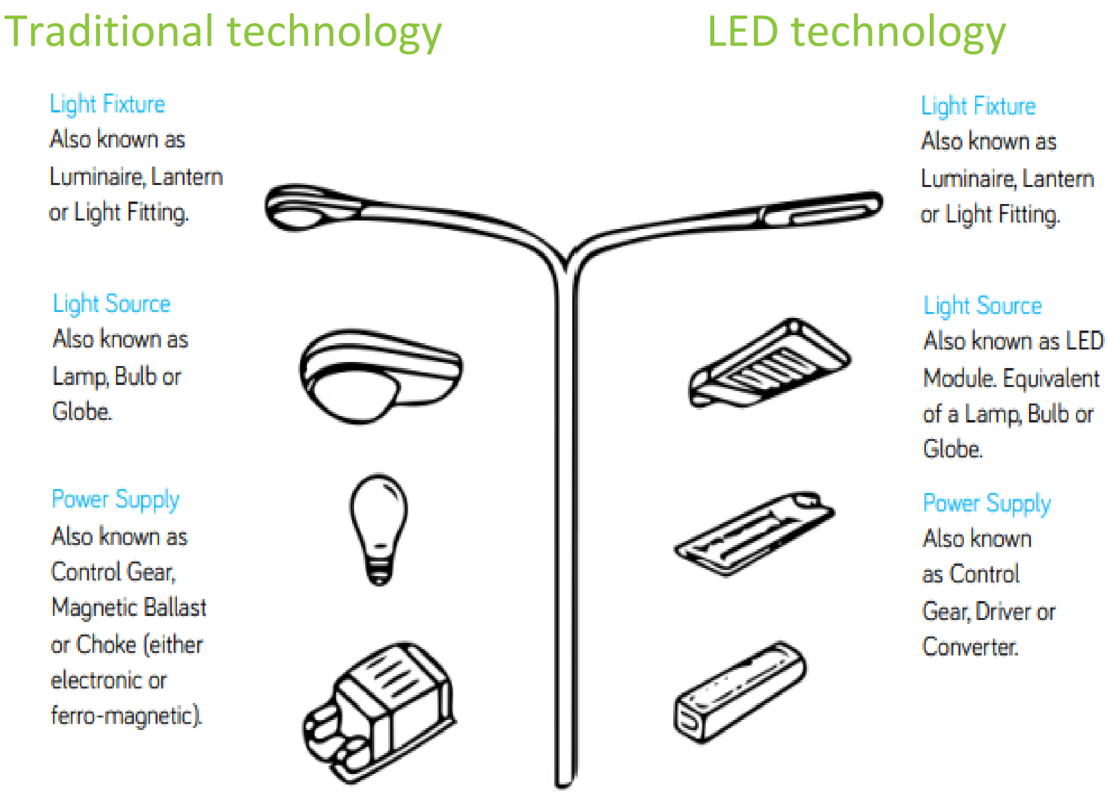
- which impact transmission costs
- when a network is experiencing peak demand.

About half of all distributors have a fixed and variable component to their charges for streetlights. The variable is usually cents per kWh for the estimated load. However, there is a variety of basis for the fixed charges, including $/columns, $/fittings, $/fixtures, or $/lamps. Fixed charges are sometimes expressed as $/month, with no physical quantity specified.

These Guidelines outline a standard approach to the pricing structures and terminology for unmetered loads. There is now an opportunity to adopt standardised terminology that is easily understood, consistently used, and applicable to traditional and newer lighting technologies.[37]

Figure 27 below is based on a diagram from the Institute of Public Works Engineering Australasia (IPWEA) is an industry body representing engineers in private consultancies and local bodies in Australia and New Zealand. The recommended terms are blue, with other commonly used terms also listed.

Figure 27. Terminology applicable for traditional and LED lighting



Recommended basis for charges

A combination of fixed and variable charges would reflect the cost characteristics of providing these services. The price level and weighting of pricing components can reflect each distributor's particular network characteristics, i.e., congested, emerging congestion, or no congestion.[38]The recommended approach is for fixed charges to be $/day/Light Fixture.

As Lighting Fixtures are permanent structures and do not change significantly from month to month, charges will be predictable and easy to maintain. Fixed charges reflect the cost of owning and

[37] The change in lighting technology has meant that some commonly used terms may not be applicable in all cases e.g., LED lights do not have bulbs.

[38] The revenue a Distributor looks to recover from unmetered load should be based on the same criteria/approach as for other loads. There will be trade-offs between cost reflectively and other factors such as simplicity and transaction costs.

maintaining the assets involved. Customers should supply a monthly schedule to distributors with the number of fixtures clearly defined.

And the variable component should be expressed as $/kWh.

Variable prices can be set to recover the element of costs associated with the impact on transmission costs and contribution of distributed unmetered load on network peak demand. The use of kWh rather kW has been proposed as kWh are required to be provided to the reconciliation manager and are currently the predominant form of variable prices. Customers should include in their monthly schedule submission the total wattage used by each light source (not just the bulb wattage), and the hours of operation, to allow a calculation of the kWh consumed during the period.

In many instances, these connections are historical anomalies, and distributors do not permit new connections in this format.

Non-lighting distributed unmetered load should be charged on the same basis as other standard unmetered loads, which are $/day and $/kWh.

Shared Unmetered Load

Shared unmetered load is defined in Part 1 of the Code as

Shared unmetered load means unmetered load at a single point of connection that is distributed across more than 1 ICP.

A shared unmetered load should ideally be charged on the same basis as other unmetered loads of a similar type. As most shared unmetered load will be street lighting, fixed or fixed and variable charges would often be applied in a right-of-way or private road. Distributors may apply a materiality threshold and are mindful of the transaction costs of administering these connections, particularly when charges for a single light are shared over consumer accounts.

Distributors must maintain records of the beneficiary ICPs of shared unmetered load on the Registry, and changes applied (and supported by EIEP1 files) should reflect the same allocation as that recorded on the Registry.

7.2 Temporary Supply

Some distributors offer a specific pricing group for metered and/or unmetered temporary supplies. Sometimes referred to as a "builders' temporary supply," these connections are commonly used for sites under construction, builders' temporary connections, and connections for concerts and other entertainment facilities.

If there is no specific group for temporary connections, the connection would be included in general or other applicable pricing groups.

A temporary connection is a consumer connection that is either:

A. removed, or
B. converted to a permanent connection,

within [12] months.

The distributor may charge temporary connections additional connection charges and/or disconnection fees.

Price components

For metered temporary supplies, the distributor should charge a fixed component

($/day). If a volume component is also charged, it should be specified as ($/kWh). If the temporary supply is metered, the meter should be read, and the volume provided to the distributor.

The distributor can use capacity and demand charges instead of or in addition to the fixed and volume charges. However, given the temporary nature of the connections, the benefit of a simple approach may outweigh other concerns, such as achieving a high degree of cost reflectivity.

A fixed ($/day) pricing structure is recommended where a temporary connection is unmetered and volume cannot be accurately calculated. However, this pricing approach can incentivise a consumer to retain a temporary connection in a high-use situation. A time limit on temporary connections or a requirement to meter high loads (with equivalent charges) can arrest a perverse outcome.

To avoid confusion, this guideline recommends that a temporary unmetered be categorised as a temporary supply rather than an unmetered supply.

7.3 Irrigation

In rural areas, some distributors have a specific pricing group for irrigation connections. Irrigation connections have significantly different load and cost characteristics than other connections:

- Irrigation peak demand occurs in summer, whereas most network peak demands occur in winter,
- Irrigation connections tend to be in lower-density rural areas (using long stretches of overhead network)
- Irrigation load is highly correlated rather than diverse. When it is warm and dry, most irrigation is switched on. This lack of diversity means the network capacity must reserve its full capacity for each irrigation connection, regardless of how infrequently it is used
- Irrigation load and the combined load profile are flat (and traditional load management and demand response techniques cannot reduce peak demand effectively).

While capacity charges are normally specified on a kVA basis, irrigation pump motors are rated in kW; therefore, $/kW/day is used as a basis for charges.

There are alternatives to grid-supplied electricity for many irrigators, such as diesel-powered pumps. Different irrigation options (surface-water pumping compared to deep-well submerged pumps) also have different energy requirements. Electricity charges should reflect the service's cost so that consumers can efficiently evaluate alternatives for water delivery.

Irrigation loads can also present significant power quality challenges, with poor power factors and high harmonics potentially affecting other network users.

The Irrigation Connection Category is for connections using energy for irrigation of agricultural land with a combined pump nameplate capacity (or equivalent measure) of greater than [20kW].

The combined capacity includes the motor load associated with the simultaneous operation of the irrigator, including intermediate or support pumps and rig drive motors on pivot irrigators.

Some distributors require that irrigation connections be exclusively used for irrigation purposes and remain separately connected from other loads (e.g., an irrigation connection and a house cannot be combined into a single supply). Where irrigation connections are required solely for irrigation use, there is an allowance for a limited additional load to provide for the practical situations irrigation consumers face, such as the requirement for lighting in a pump shed.

Some distributors allow consumers to combine irrigation loads and other loads with a different load profile to encourage better consumer asset utilisation. We recommend distributors avoid combining loads as combined loads dilute the intended pricing signal created by having the irrigation load group.

Distributors should clearly state their rules for all their price category groups.

Price Components

The standard price components distributors use for irrigation connections are set out in Table 9.

Table 9. Price components irrigation

Price Component	Metric	Description
Fixed charge	$/day	A small charge is consistent with other comparable size categories to reflect the fixed cost associated with managing a connection, determining quantities, and applying prices.
Irrigation capacity charge - Uncontrolled	$/kW/day	Applied to the combined capacity. It can be applied all year or during an “irrigation season” defined by the distributor (in which case the price is effectively nothing outside this season).
Interruptible irrigation capacity charge Controlled	$/kW/day	A lower price is applied instead of the irrigation capacity charge when the customer allows the distributor to interrupt the supply to the irrigator based on a defined service level target.
Power factor correction rebate	$/kVAr/day	Based on the rated kVAr of capacitance provided at the connection and needed to meet the power factor requirements specified by the distributor.
Harmonic charge	$/kW/day	Applied to the combined capacity where current harmonic levels exceed the maximum levels set by the distributor.
Volume charge	$/kWh	Volume pricing on either a controlled, uncontrolled, or day/night pricing basis. Used to allocate non-capacity-based costs.

14 Examples of permitted additional load include a single lighting circuit for the pump shed, a single plug circuit up to 20 amps (for miscellaneous use, an electric fence unit, etc.), a stock water pump up to 5kW, domestic water pump up to 2kW, and air conditioning load for control equipment.

The capacity charge is usually a significant portion of the charges reflecting the fixed costs associated with providing the capacity, regardless of the frequency of use. The capacity charges aim to recover costs, avoid overcharging for high utilisation, and avoid under charging for low utilisation.

The distributor will not waive the charge for infrequent use (eg. where a pump is used as a backup) because the capacity must still be reserved for a situation where it is required. The requirement for a backup supply is also likely to coincide with other customers.

Volume charges do not tend to reflect closely the costs of providing the service.

If the charges are not levied each month, the irrigation season should be specified as 1 October to 31 March each year, unless specific issues exist.

Defining an irrigation season charge and applying charges only during that season rather than year-round can align the consumer's costs with their use of the irrigation supply. It also reduces the incentive to avoid charges through seasonal disconnection.

Although irrigation often extends into April, a season end of March 31 aligns with the end of the pricing year, providing a simpler basis for application and a price that remains the same for each complete season.

Volume pricing is useful for allocating non-capacity-based costs and to reflect any contribution to winter peaks (eg. transmission peaks) from residual load at the connection (such as domestic water pumping).

7.4 Power Factor

Power factor is a way of measuring how efficiently electrical current is converted into usable power. Low power factors can lead to lower than 'normal' voltages and consequently cause performance issues for network users, lower the delivery capacity of assets, and negatively impact network equipment. The transmission benchmark agreement in the Code also contains fixed requirements for the aggregated power factor measured at each GXP, which may be enforced by Transpower and require the distributor to take steps to mitigate a deviation from the required level.

A kVAr (Kilovolt Ampere reactive) charge is a common power factor charge. kVAr charges are used to recover the costs (or potential costs) of power factor deterioration caused by consumer behaviour at a connection. Power factor charges are complex and intended to incentivise consumers to take steps to correct their power factor. Accordingly, power factor charges may not be appropriate for small connections.

The TPM does not include a power factor charge

The TPM does not include a method of a kVAr charge on reactive power.[39] Transpower believed that a kVAr charge would add significant complexity, as shown in.

Figure 28. kVAr charge would add significant complexity

> Transpower considered that "static voltage stability concerns can generally be managed by relatively low cost transmission components (capacitors and reactors)…[and]…a kVAR charge would add significant complexity (and so development and implementation cost) to the new TPM that is unlikely to be offset by material efficiency or reliability benefits."[40]

[39] Electricity Authority, Transmission Pricing Methodology 2022, Decision paper (TPM Decisions Paper), paragraph 11.3 at page 85.
[40] TPM Decisions Paper, paragraph 11.6 at page 85.

Six distributors servicing 65% of New Zealanders have a power factor charge

Currently, distributors use several approaches to determine power factor charges for loads that use reactive power at higher than permitted levels. There are common elements such as a 0.95 threshold.

Six distributors servicing 65 percent of New Zealand consumers (by number) have a similar methodology for determining chargeable quantities for power factor. The approach typically determines the chargeable quantity by calculating the largest difference between the consumer's total kVArh and the kVArh at 0.95 power factor (determined by dividing the kWh demand by three), recorded in any one half-hour period during each month.

There is some variation in periods where quantities are measured. The most common times are between 7.00 am and 8.00 pm (i.e., pricing periods 15 to 40) on weekdays and public holidays. However, distributors should consider aligning with other price components when setting periods for power factor charges in the interests of consistency and simplicity.

An alternative approach to determining the power factor is to use a similar calculation but calculate the sum of the differences between kVArh and a third of the kWh across each half-hour period to determine the chargeable power factor quantity.

The key differences between this and the first approach are that the:

- first approach charges for the single maximum half-hour reactive demand for loads below 0.95 power factor,
- the alternative approach charges the total reactive energy for loads below 0.95 power factor.

The first approach is better aligned with demand-based charges, whereas the alternative approach is more closely aligned to volume-based charges

Analysis

Shown in Table 17 is an example of how distributors can present their power factor calculations.

Table 17 and Table 18 in Appendix 2 show that consumers with infrequent occurrences of poor power factor (<0.95) in a month will get a stronger price signal under the "primary approach" than the "alternative approach". A consumer with a consistently poor power factor (<0.95) will receive a much stronger price signal under the alternative approach.

The two approaches allow distributors to address constraints and conditions experienced on their networks.

If a consumer's power factor is below 0.95, lagging, the distributor may apply power factor charges. Where the consumer's metering equipment does not record the information to determine the power factor, the distributor may install equipment to monitor the power factor or require certification that the appliances installed on-site operate with a power factor of 0.95 or better.

The power factor charge should be determined by one of the following approaches:

Primary Approach - Single maximum half-hour reactive demand.

The power factor amount is determined each month where a consumer's power factor is less than 0.95, lagging. This power factor amount (kVAr) is represented by twice the largest difference between the consumer's kVArh recorded in one half-hour period and a third of the kWh demand recorded in the same half-hour period each month. The charge applies between 7:00 am and 8:00 pm (periods 15 to 40) on weekdays, including public holidays.

Alternative Approach - Total reactive energy for loads.

The power factor amount is determined each month where a consumer's power factor across any half-hour period is less than 0.95 lagging. This power factor amount (kVArh) is represented by the difference between the sum of the consumer's kVArh and a third of the kWh demand recorded in each half-hour period. The charge applies across all periods and days of the week (i.e., Monday-Sunday).

Calculation detail

The following two equations can represent the two approaches to power factor:

Primary Approach - Single maximum half-hour reactive demand

Max_{wdx} (max (($kVArh_i$ - kWh_i/3)* 2,0)) **Where:**

wd_x represents weekdays Monday-Friday (including public holidays) for month *x,*

$kVArh_i$ is the half-hourly reactive (kVArh) quantity for period *i,*

kWh_i is the half-hourly active (kVArh) quantity for period *i,* and

i represent the trading periods 15 to 40.

Alternative Approach - Total reactive energy for loads

Sum_{adx} (max (($kVArh_i$ - kWh_i/3), 0)) **Where:**

ad_x represents all days (Monday-Sunday, including public holidays) for month *x,*

$kVArh_i$ is the half-hourly reactive (kVArh) quantity for period *i,*

kWh_i is the half-hourly active (kWh) quantity for period *i,* and

i represent the trading periods 1 to 48.

Power factor for non-half hourly connections

Poor power factor is not limited to connections with half-hourly metering. Non-half-hour sites also can contribute significantly to poor power factor on a network. While non-half-hour connections are typically smaller regarding their individual connected capacity, their total aggregated load often exceeds the total load for half-hour connections.

For this reason, a small number of distributors have power factor charges (or rebates) that apply for specific connections without half-hourly metering. Typically, these charges apply for specific price categories representing a particular sub-segment of connections with known power factor issues (such as irrigation load).

8. Documentation and Terminology

8. Documentation & Terminology

Distributors prepare and publish pricing details that apply under their default or alternative distributor agreements with electricity retailers and, in some cases, with end consumers to meet regulatory disclosure, price path, and Code requirements.

Over time the documents and terminology used by distributors and the terms set out in the regulatory requirements have diversified. This guideline establishes standard terms that promote consistency, which simplifies pricing documentation.

8.1 Published documentation

It is recommended that distributors publish the following standardised pricing documentation on their websites:

Delivery price schedule

The delivery price schedule should be a compact (one or two pages) document summarising delivery prices within a stated date range and key terms associated with the prices (see pricing schedules below). The intended audience of this schedule is electricity retailers and consumers, and it should be as clear and simple as possible. It is not intended to meet all disclosure requirements. Schedules may be supplemented with additional pricing information in the pricing policy (discussed below). Where distributors have multiple pricing regions, multiple schedules may be used.

Consideration was given to a standard approach that included meeting the information disclosure and price-path regulatory requirements. However, there are differences between these requirements, different requirements apply to different distributors, and the requirements are set to change. These guidelines specify a simple delivery price schedule to provide a consistent approach with the most relevant information for electricity retailers and consumers.

Pricing methodology

The pricing methodology describes each distributor’s approach to setting prices. It includes information on key considerations, calculations, pricing strategy (if applicable), and a discussion on the consistency of prices with the Pricing Principles. It is intended to fulfil multiple objectives, including:

- compliance with the Commission’s Information Disclosure Regulations[41],
- for non-exempt distributors' compliance with the price path under the DPP,
- provision of transmission and/or pass-through price components, and
- the Authority’s Distribution Pricing Principles and Information Disclosure Guidelines.

[41] As per section 2.4 Pricing and Related Information.

Pricing policy

A pricing policy is an optional document detailing how connection categories are determined, price-plan definitions (e.g., peak control hours), how chargeable quantities are established, and how prices are applied. This information may be attached to the pricing schedule.

Pricing guide

A pricing guide is an optional document or webpage that is short, consumer-friendly, and explains the key features and rationale behind delivery pricing.

Loss factor schedule

A loss factor schedule provides the declared loss factors. The Reconciliation Manager uses the schedule to reconcile energy in the market and electricity retailers when calculating retail pricing.

There are four types of network losses:

(a) technical losses—the difference between the energy injected into a network and the energy delivered to points of connection,
(b) non-technical losses—are any form of unexplained losses, for example, metering inaccuracy and errors or omissions in traders' back-office systems,
(c) reconciliation losses—the combination of technical and non-technical losses, and
(d) unaccounted for electricity (UFE)—the difference between reported energy injected into a network and the reported energy extracted from the network after being adjusted for losses.

The Authority advocates calculating loss factors in its *Guidelines on calculating and using loss factors for reconciliation purposes*[42]. The guidelines recommend:

- a methodology for calculating reconciliation loss factors; and
- an annual loss factor report.

The loss factor codes must match those recorded by the distributor against ICPs on the Registry. Under a standard approach, loss factors should be set out on a different schedule, with an updated version issued yearly when prices are issued even if loss factors remain unchanged.

Documents should be available from each distributor's website via a visible "pricing" link on the home page. The terminology in Table 10 should be used throughout documentation and any related material.

[42] A copy of the Authority's guideline can be found on its website at https://www.ea.govt.nz/assets/dms-assets/23/23580Guidelines-on-the-calculation-and-the-use-of-loss-factors-for-reconciliation-purposes.pdf

Table 10. Recommended Terminology

Term	Usage/meaning
Delivery	The complete electricity delivery service, including both distribution and transmission services
Delivery price	The total delivery price for both distribution and transmission services
Distribution	The part of the electricity delivery service that is provided using the distributor's assets
Transmission	Transpower's national transmission assets and other assets that provide alternative transmission services are part of the electricity delivery service.
Price	The amount charged per unit of measure purchased. e.g., $0.0468 per kWh, or $0.15 per connection per day. In limited situations, a price can appropriately be described as a charge that is not dependent on a measured quantity, e.g., new connection charge, invoice charge, etc.
Quantity	The chargeable quantity the price is applied against determines the amount charged, e.g., 656 kWh, or one connection for 31 days.
Charge	The amount charged is the product of the price and the quantity.

The recommendation is that **Price X Quantity = Charge.**

Avoiding the terminology in Table 11 will support consistency and standardisation.

Table 11. Terminology to Avoid

Term to avoid	Reason	Alternative to use
Tariff, tariff rate, tariff charge	It has negative, "tax-like" connotations and implies something that is not avoidable.	Price
Rate, charge rate, Fee	General standardisation.	Price, or charge where the amount is not dependent on a quantity - e.g., a new connection charge.
Line charge	In the past, some distributors used this term to describe the total, and others only the distribution component of services. Often confused as the "fixed daily line charge" on a retail electricity account.	Price
3% charge increase	The charge is the product of price and quantity. Prices moving by 3% do not imply that charges will also move by 3% because a different amount might be consumed	3% price increase
Charge schedule	A charge is the product of price and quantity. Schedules only show prices.	Delivery price schedule

We note that "tariff" is widely used in New Zealand and other jurisdictions, but we have chosen to use price and charges.

8.2 Pricing Schedules

This section provides guidelines to promote consistency between distributors' published delivery price schedules for retailers and consumers.

Delivery Price Schedule

Distributors prepare more detailed schedules within their pricing methodology and for publication in newspapers to meet the specific regulatory and disclosure requirements.

It is recommended that the "Delivery Price Schedule" that sets out the main delivery prices should include the following information:

- A title in the format "Electricity Delivery Price Schedule for [ABC Ltd]" (and pricing region, if applicable)
- State the applicable period as either "Applicable from [date]" or "Applicable from [date] to [date]"
- A brief introduction including a description of the pricing area covered, and the party to which charges are applied (usually electricity retailers)
- A table of delivery prices.

The table of prices should include:

- Price category code – the code recorded against each ICP on the Registry and entered in EIEP1 & EIEP12 (a price category name may be included as well)
- Category count – the number (or estimated number) of connections (ICPs) that are in the price category
- Price component name – each price category will have one or more components
- Price component code – the code that is entered in EIEP1, EIEP2, and EIEP12
- Each delivery price component is expressed as a GST-exclusive amount (transmission/pass-through components are not to be shown, these are instead provided within the pricing methodology where required)
- Units - the metric the price is expressed in; e.g., $/kWh, $/connection/day, $/kW/day
- A clear indication of any price components that are applied against loss adjusted or GXP metered quantities, rather than ICP measured or metered quantities
- Details of any posted discount or rebates.

Each schedule should show prices for the current year and the immediately preceding pricing year.

Where prices change or are withdrawn, the information disclosure requirements require distributors to publish the changed price alongside the preceding price. A single schedule for the pricing year is a straightforward way to achieve this, providing a simple and durable framework for publishing prices.

Separate pricing regions can be shown in separate schedules.

Any notes that promote understanding of the pricing schedule consistent with the short form document could be included.

It is recommended that metering or ancillary service pricing (such as meter reading or connection services) be scheduled separately.

Scheduled prices match those provided in EIEP12 files, including being expressed in the same metric (e.g., $/con/day) and with the same number of decimal places. Prices published in the schedule are not to be rounded. They must be the prices applied in billing.

These guidelines recommend that distributors express prices in the formats shown in Table 12.

Table 12. Recommended price formats

Price type	Format	Example
Fixed prices	$/con/day (4 decimal places (dp))	$1.3687/con/day
Volume prices	$/kWh (5 dp)	$0.12544/kWh
Demand prices (usually based on metered demands or equipment nameplate)	$/kW/day (4 dp)	$2.5688/kW/day
Capacity prices(usually based on fused capacity or transformer nameplate)	$/kVA/day (4 dp)	$2.5688/kVA/day

Decimal places

Prices in the pricing schedule should be to the number of decimal places at which they are billed. Trailing zeros do not need to be used; however, the number of decimal places should be consistent for a given price. For example, where a volume price is billed to four decimal places, as shown in Table 12, all volume prices must be specified to four decimal places (including trailing zeros).

Although some consumer groups (particularly lower capacity consumer groups) are more familiar with prices expressed in cents (e.g., c/kWh), this Guideline specifies that prices should be published in a dollar format.

Prices that are not volume-based should be set and applied daily (rather than monthly) to allow accurate calculations when connections switch between retailers or change status.

The following units and abbreviations are shown in Table *13* and should be used where applicable (note the capitalisation).

Table 13. Abbreviations for pricing documents

Term	Abbreviation
kilowatt hour	kWh
kilowatt	kW
kilovolt ampere hour	kVAh
kilovolt ampere	kVA
kilovolt ampere reactive hour	kVArh
kilovolt ampere reactive	kVAr
day	day
year	yr
connection or ICP	con or ICP
dollars	$

Specifying a $ format in these guidelines reflects retailers' feedback that the same metric is used throughout a schedule, not a mix of dollars and cents. Many distributors specify prices (for example, equipment prices) that exceed $10/day, and the regulated EIEP12 "Tariff rate change information" file format requires that prices be published in dollars.

Delivery Price Schedule for The Power Network Ltd

Effective from 1 April 20YY

Table 14 provides an example of a distribution pricing schedule—

The prices in this schedule are used to charge electricity retailers to deliver electricity to the [Electricity Network] region serviced by our electricity network. Electricity retailers determine how to allocate this cost with energy, metering, and other retail costs when setting the prices in your power account.

Table 14. Example of a distribution pricing schedule

Code	Description	Register Content	Delivery Price	Units
Residential Low Fixed Charge / Price category code: RLU / Number of consumers: 1234				
RLFC	Daily price		0.150	$/con/day
RLVC1	All inclusive	N18	0.06543	$/kWh
RLVC2	Controlled	CN18	0.05766	$/kWh
RLVC3	Night only	CN8	0.03565	$/kWh
RLVC4	Uncontrolled	UN24	0.12432	$/kWh
Residential standard users / Price category code: RSU / Number of consumers: 4321				
RSFC	Daily price		0.760	$/con/day
RSVC1	All inclusive	N18	0.05543	$/kWh
RSVC2	Controlled	CN18	0.03766	$/kWh
RSVC3	Night only	CN8	0.02565	$/kWh
RSVC4	Uncontrolled	UN24	0.11432	$/kWh
General – Unmetered supply – Lighting / Price category code: GUL / Number of consumers: 154				
GSFC	Daily fixed price		0.0341	$/fitting/day
GSVC	Variable street lighting		0.06540	$/kW/day
General – Temporary supply / Price category code: GTS / Number of consumers: 85				
GTFC	Daily fixed price		1.261	$/con/day
GTVC	Variable		0.04650	$/kWh
General – Metered supply Group 1 (8-150kVA) / Price category code: GM1 / Number of consumers: 985				
G1FC	Daily fixed price		1.170	$/con/day
G1CC	Daily capacity price		0.0456	$/kVA/day
G1VC	Uncontrolled	UN24	0.04080	$/kWh
General– Metered supply Group 2 (151-350kVA+) / Price category code: GM2 / Number of consumers: 75				
G2FC	Daily fixed price		3.900	$/con/day
G2VCC	Daily capacity price		0.0274	$/kVA/day
G2VC	Uncontrolled	UN24	0.04080	$/kWh
Large Commercial– Group 3 (351kVA+) / Price category code: LCM / Number of consumers: 26				
LCFC	Daily fixed price		9.500	$/con/day
LCCC	Daily capacity price		0.0162	$/kVA/day

Code	Description	Register Content	Delivery Price	Units
LCDC	Daily demand price		0.4337	$/kW/day

Notes: All prices exclude GST. Full details on how prices are applied are included in our Delivery Price [Policy/Guide] and how we establish prices in our Pricing Methodology, both available from our website. The delivery price is the total covering distribution, transmission, and other “pass-through” costs. For a breakdown of these components, please refer to our Pricing Methodology.

9. Billing format and processes

9. Billing format and processes

These guidelines outline and recommend formats and processes used in billing delivery charges.

Different processes will exist if distributors use an ICP-priced methodology compared to a GXP-priced methodology. An ICP-priced methodology is used by most distributors and utilises individual ICP consumption detail for volume-based charges. A GXP-priced methodology uses GXP throughput data and assigns charges to each retailer using Reconciliation Manager data and Large Commercial consumption.

9.1 ICP-priced networks

Where an ICP-priced methodology is used, the distributor usually relies on each retailer to provide consumption data for every connected ICP. The Authority has mandated that consumption be provided via EIEP1 and EIEP3 files. As of January 2020, EIEP1 files:

- must be provided as “replacement RM normalised “ for the mass market (MM) ICPs for both interposed and conveyance,
- “as billed” is an option available to distributors with half-hour (HHR) ICPs,
- traders may only provide “X” partial replacement files if the distributor agrees.

9.2 GXP-priced networks

GXP-priced networks do not use EIEP1 files to determine charges to retailers[43]. Instead, the distributor should use reconciliation manager GR-040 files to determine the volumes and/or demands attributable to each retailer. EIEP3 files will provide additional information about Category 2 (HHR) where applicable, 3, 4, and 5 metered ICPs. Using this data in combination with the GR-040 files will enable the chargeable GXP volumes/demands to be calculated.

For a day-based volume GXP pricing example, if the GR-040 volume is 500,000kWh, the combined loss-adjusted volume from ICP-priced connections in EIEP3 files is 150,000kWh, then the volume for GXP charges is 350,000kWh.

In communicating the billing data back to retailers, EIEP2 files provide summary billing information. These should accompany the invoices.

9.3 Method of exchanging billing files

The Electricity Authority provides a Secure File Transport Protocol (SFTP), known as the Registry transfer hub “the Hub,” where participants are provided with an EIEP outbox (for sending files) and an EIEP inbox

[43] Some GXP-priced distributors use an ICP-based billing approach for specific pricing groups such as Low Fixed Charge Residential consumers, to maintain compliance with the LFC Regulations.

(for receiving files). The Authority recommends using this facility for receiving EIEP billing files from and sending EIEP billing files to retailers. Data transmission via other methodologies must be secure (i.e., password-protected emails). Failure to send information through secure means increases business liability risk.

Non-EIEP billing files (such as invoices for payment) can also be exchanged via the Hub in a single zip file in the following naming format:

- Sender_Utility Type_Recipient_File Type_Report Month_Report run Date_ Unique identifier.zip
- E.G. ORON_E_FLCK_INVOICE_201606_20160608_428.zip

9.4 Scaling

Some distributors scale retailers' volumes for any unaccounted for energy (UFE) on their network for the month and then reverse this in later months. Scaling helps smooth the monthly impact of estimations from retailers.

The ENA recommends that distributors treat all retailers equally using a transparent methodology.

9.5 Processes

Documentation of billing processes is important to ensure transparency of work activities to the organisation and auditors. Documented processes enable greater continuity of work and can be used as training tools for new employees. Documenting processes allow for a conscious examination of what you do and why.

A documented process should clearly define the tasks, objectives, triggers, inputs, and outputs. Each step of the process should state who is responsible, what must happen, and the sequencing of the work.

The ENA recommends that each distributor internally document all key billing processes and review them periodically to ensure they remain current.

9.6 Invoice Content

It is recommended that invoices should provide the total amounts charged for each price component code and show the following:

- Price category code and price category code name (e.g., "Residential Low fixed Charge" - RLU)
- Price component code and component code name (e.g., "RLFC - "LFC daily Price" and "RLVC1" - "LFC All Inclusive")
- Chargeable quantity (matching the total of the supporting EIEP data files)

- Delivery price
- Resulting charge.

The price shown is to match the price on the published price schedule, be in the same metric (e.g., $/con/day), and have the same loss factor and UFE basis as published in the price schedule (that is, any loss or UFE adjustment is to be applied to the chargeable quantity, not to the price). Prices shown on invoices are not to be rounded. They are to be the prices used in the calculation of charges. Only the total delivery price should be stated on invoices.

9.7 Basis of calculation

Prices should be set and applied daily (rather than monthly); charges will vary based on the number of days in a month. The invoice detail should be provided on a GST exclusive basis, with GST added to the total at the end.

All charges should be rounded to the nearest cent (calculated and rounded on an ICP-by-ICP basis for each chargeable component, consistent with the EIEP definition for network charge).

Unrounded prices are to be shown and used in the calculation, but charges (after applying the applicable chargeable quantity quantities) are rounded to the nearest cent.

Appendix

Appendix 1. Worked Examples for LFC Compliance

Chapter 3 of these guidelines outlined three approaches distributors can take to set prices for residential connections. Below we provide three examples of how distributors might demonstrate compliance with the LFC Regulations under each approach.

Dual Residential Plan

Under a dual residential plan, a distributor gives residential connections a choice between being on a Residential plan or a corresponding Residential LFC plan. Each distributor's residential plan must also offer a corresponding Residential LFC plan. Resulting in multiple Residential plans and corresponding Residential LFC plans.

Table 15 shows a worked compliance example for two Residential plans and two corresponding Residential LFC plans, based on average annual consumption of 8,000kWh.

Table 15: Results of worked example for dual residential plan

Price Code	Fixed Daily Charge	Variable Day	Variable Night	Average annual charges (based on 8,000kWh)
RES01	$0.5000	$0.1400	$0.0560	$1,100.72
LFC01	$0.3000	$0.1511	$0.0604	$1,100.72
RES02	$0.7500	$0.1204	$0.0481	$1,063.32
LFC02	$0.3000	$0.1454	$0.0582	$1,063.32

Note: The calculation assumes a 70/30 Day/Night split on the 8,000kWh consumption

Compliance against the LFC Regulations is demonstrated by showing that the "average consumer" would pay the same charges if they were on either plan. Distributors can demonstrate compliance by calculating the average consumer charges for both the Residential plan and a corresponding Residential LFC plan. For example—

> (fixed daily charge x number of days in the year) + ((average annual consumption x Day consumption assumption) x variable day charge) + (average annual consumption x Night consumption assumption) x variable night charge))

Based on the formula above:

- Residential plan 01 (RES01) would be derived by—

  RES01 = ($0.5000 x 365) + ((8,0000 x 0.70) x $0.1400) + (8,000 x 0.30) x $0.0560))

  = $1,100.72

- Residential LFC plan 01 (LFC01) would be derived by—

  RES01 = ($0.3000 x 365) + ((8,0000 x 0.70) x $0.1511) + (8,000 x 0.30) x $0.0604))

  = $1,100.72

Single Residential Plan

Under a single residential plan, a distributor places all residential connections on an LFC plan. Because all residential connections are charged the same fixed price component, there is no comparable price against which the LFC needs to be tested.

Accordingly, where distributors adopt a single residential plan approach, these guidelines recommend that distributors write to the Authority and outline how they meet the LFC Regulations.

Figure 29. Example LFC compliance statement

All premises used or intended for occupation by a person principally as a place of residence are included in the X1, Residential Category. We do not apply any other price to domestic consumers. Prices applicable to domestic consumers effective 1 April 20[YY] are shown in Table 1 below.

[Include a copy of Residential prices from your pricing schedule here]

Our prices comply with the low fixed charge regulations as follows.

- Section 4 and 5 of the amended regulations—the fixed daily supply charge is not more than [prescribed per the LFC regulations] cents per day, excluding goods and services tax.
- Section 9 and 15—by default of having only one domestic consumer group, and all domestic consumers in that one consumer group, we ensure that the average consumer pays no more per year on a low fixed charge tariff option than on any alternative tariff option.
- Section 10—the low fixed charge is not unreasonably detrimental to the interests of low-use consumers.
- Section 14—there is only one fixed charge for the line function services supplied to the home. We are not recovering any charges associated with the delivered Electricity to the home other than those permitted under subclause (c).
- Section 16—the variable charges are not tiered or stepped, except to the extent permissible by subclause (2). Our fees for special services, rebates, or discounts are consistent with those offered to other consumers on our network.
- Section 23—tariffs regarding homes for the supply of delivered Electricity or component of delivered Electricity. The number of homes on the low fixed charge tariff option on our network is provided in Table 1 on the previous page. Attachment A is a full copy of our Pricing Schedule effective 1 April 20[YY].

Single General Plan

Under a single general plan, a distributor gives consumers a choice between being on a General Plan or a corresponding General LFC Plan. Compliance against the LFC Regulations is demonstrated by showing that the "average consumer" would pay the same charges if they were on either plan. Distributors can demonstrate compliance by calculating the average consumer charges for the General Plan and a corresponding General LFC plan. For example—

> (fixed daily charge x number of days in the year) + (Peak kVA x (demand charge x number of days in the year) + ((average annual consumption x Day consumption assumption) x variable day charge) + (average annual consumption x Night consumption assumption) x variable night charge))

Based on the formula above:

- General plan 01 (GEN01) would be derived by—

  GEN01 = ($0.2500 x 365) + (8 x ($0.2500 x 365) + ((8,0000 x 0.70) x $0.0.0426) + (8,000 x 0.30) x $0.0170))

  = $1,100.72

- Residential LFC plan 01 (LFC01) would be derived by—

  RES01 = ($0.3000 x 365) + (8 x ($0.2000 x 365) + ((8,0000 x 0.70) x $0.0621) + (8,000 x 0.30) x $0.0248))

  = $1,100.72

Table 16 shows a worked compliance example for two Residential plans and two corresponding Residential LFC plans, based on average annual consumption of 8,000kWh.

Table 16: Results of worked example for dual residential plan

Price Code	Fixed Daily Charge	Demand Charge (peak kVA/per day)	Variable Day	Variable Night	Average annual charge (based on 8,000kWh)
GEN01	$0.2500	$0.2500	$0.0426	$0.0170	$1,100.72
LFC01	$0.3000	$0.2000	$0.0621	$0.0248	$1,100.72

Note: The calculation assumes a 70/40 Day/Night split on the 8,000kWh consumption

Appendix 2. Example Power Factor Calculations

Shown in Table 17 is an example of how distributors can present their power factor calculations.

Table 17. Example One: "One-off " poor power factor

Date	Period	kWh	kVAh	kVArh	Power Factor	Chargeable Quantity Method 1	Chargeable Quantity Method 2
01/01/2016	15	95	100	31	95%		
01/01/2016	16	100	106	35	94%	3.6	1.8
01/01/2016…	17	145	180	107	81%	116.6	58.3
31/01/2016	46	110	115	34	96%	n/a	
31/01/2016	47	100	106	35	94%	n/a	1.8
31/01/2016	48	100	105	32	95%	n/a	
Total						**116.6**	**62.0**

Where Chargeable quantity - primary approach = max((kVArh – kWh/3)*2, 0) (in time periods 15 to 40 only).

Chargeable quantity (alternative approach) = Sum (max(kVArh – kWh/3, 0))

Distributors may also want to charge for power factors constantly. An example of the calculation of the constant power factor is shown in Table 18.

Table 18. Example Two: Constant poor power factor

Date	Period	kWh	kVAh	kVArh	Power Factor	Chargeable Quantity Method 1	Chargeable Quantity Method 2
01/01/2016	15	95	101	34	94%	5.3	2.6
01/01/2016	16	95	101	34	94%	5.3	2.6
01/01/2016	17	95	101	34	94%	5.3	2.6
31/01/2016	46	95	101	34	94%	n/a	2.6
31/01/2016	47	95	101	34	94%	n/a	2.6
31/01/2016	48	95	101	34	94%	n/a	2.6
Total						**116.6**	**3,869 (2.6 x 31 x 48)**

Where Chargeable quantity (approach 1) = max((kVArh – kWh/3)*2, 0) (in time periods 15 to 40 only).

Chargeable quantity (approach 2) = Sum (max(kVArh – kWh/3, 0)).

The number of chargeable periods used will affect the typical level of charges. Applying the primary calculation method, power factor charges of \$0.20-\$0.25/kVAr per day are typical. Under the alternative approach, charges of \$0.04/kVArh may reflect the higher chargeable quantity from using more periods.

Appendix 3. Meter Installation Characteristics

Table 19 shows Table 1 (Metering installation characteristics and associated requirements) from Schedule 10.1 of the Electricity Industry Participation Code

Table 19. Extract from Code - Metering installations characteristics.

Defining Characteristics				
Metering Installation Category	Primary voltage (V)	Primary current (I)	Measuring transformers	Metering installation certification type
1	V < 1kV	1 ≤ 160A	None	NHH or HHR
2	V < 1kV	1≤ 500A	CT	NHH or HHR
3	V < 1kV	500A < I ≤ 1200A	CT	HHR only
	1kV ≤ V ≤ 11kV	I ≤ 100A	VT & CT	
	11 kV ≤ V ≤ 22kV	I ≤ 50A		
4	V < 1kV	I > 1200A	CT	HHR only
	1kV ≤ V < 6.6kV	100A < I ≤ 400A	VT & CT	
	6.6kV ≤ V < 11kV	100A < I ≤ 200A		
	11kV ≤ V < 22kV	50A < I ≤ 100A		
5	1kV ≤ V < 6.6kV	I > 400A	VT & CT	HHR only
	6.6kV ≤ V < 11kV	I > 200A		
	V > 11kV	I > 100A		
	V > 22kV	Any current		

Appendix 4. Register Content Codes

Participants use register content codes and periods of availability for validating the correct application of delivery prices, network reporting and billing, retailer pricing, consumer invoicing, the certification of metering installations, and creating submission information for the reconciliation manager. Listed in Table 20 are the register content codes approved by the Authority.[44] The register content codes grandfathered by the Authority are listed in Table 21.

Table 20: Register Content Codes Approved for use

Tariff Type	Register Content Code	Description
Day	D	Only to be used with N. Daytime of an uncontrolled 2-channel day/night meter, switched between channels at fixed times via an internal time clock or external signal.[45]
Day Controlled	DC	Only to be used with NC. Daytime of a 2-channel day/night meter switched between channels at fixed times via an internal time clock or external signal. All metered load is subject to control at any time via a load control device, and consumption is separately recorded for the day and night periods.
Day Inclusive	DIN	Only to be used with NIN. Day time of a 2-channel day/night meter switched between channels at fixed times via an internal time clock or external signal. All metered load on the channel combines controlled and uncontrolled loads.
Embedded Generation	EG	
Emergency	INEM	Load on the channel is a combination of load controlled only in an emergency and uncontrolled load.
Inclusive	IN	Load on the channel is a combination of controlled and uncontrolled loads.
kVA demand	AD	kVA MDI
kVAh	AH	Cumulative kVA channel
kVAh – 5 min	7052	5-minute recorded channel kVAh
kVAh – 30 min	7302	30-minute recorded channel kVAh
kVArh	RH	Reactive meter register

[44] Electricity Authority, Register content codes, 2017 Operational Review, Decisions, and summary of submissions, 20 March 2018, Appendix B at page 32.
[45] Day/Night uncontrolled—see grandfathering comment at

Table 21

Tariff Type	Register Content Code	Description
kVArh – 5 min	7056	5-minute recorded channel kVArh
kVArh – 30 min	7306	30-minute recorded channel kVArh
kW Demand	KD	kW MDI
kWh – 5 min	7054	5-minute recorded channel kWh
kWh – 30 min	7304	30-minute recorded channel kWh
Metered streetlights	SL	Only applies to NHH meter channels used for streetlights.
Night	N	Only to be used with D. Night-time of an uncontrolled 2-channel day/night meter, switched between channels at fixed times via an internal time clock or external signal. [46]
Night Boost	NB	For a single-channel meter, the load is switched on/off at fixed times during the night period and a boost period during the day via a load control device.
Night Controlled	NC	Only to be used with DC. Night-time of a 2-channel day/night meter switched between channels at fixed times via an internal time clock or external signal. All metered load is subject to control at any time via a load control device, and consumption is separately recorded for the day and night periods.
Night Inclusive	NIN	Only to be used with DIN. Night-time of a 2-channel day/night meter switched between channels at fixed times via an internal time clock or external signal. All metered load on the channel combines controlled and uncontrolled loads.
Night Only	NO	For a single-channel meter, the load is switched on/off at fixed times for the night period via a load control device.
Off-peak	OP	Use PK/OP for 2-channel peak/off-peak and PK/OP/SH for 3-channel peak/off-peak/shoulder metering configurations.
Peak	PK	Use PK/OP for 2-channel peak/off-peak and PK/OP/SH for 3-channel peak/off-peak/shoulder metering configurations.
Shoulder	SH	Use PK/OP for 2-channel peak/off-peak and PK/OP/SH for 3-channel peak/off-peak/shoulder metering configurations.
Summer	S	Records consumption during summer.
Summer Day	SRD	Records day consumption during summer
Summer Night	SRN	Records night consumption during summer

[46] Supra n45

Tariff Type	Register Content Code	Description
Summer Weekday	SWD	Records consumption during summer weekdays.
Summer Weekday Day	SWDD	Records day consumption during summer weekdays.
Summer Weekday Night	SWDN	Records night consumption during summer weekdays.
Summer Weekend	SWE	Records consumption during summer weekends.
Summer Weekend Day	SWED	Records day consumption during summer weekends.
Summer Weekend Night	SWEN	Records night consumption during summer weekends.
Uncontrolled	UN	No-load on the channel is subject to control via a load control device
Weekday	WD	Records consumption during weekdays
Weekday Day (Mon-Fri)	WDD	Must be used with WED and may be used with other register content codes for the night period. Record day consumption during weekdays. Non-seasonal equivalents of SWDD and WWDD (Summer and Winter weekday daytime)
Weekend	WE	Records consumption during weekends
Weekend Day	WED	Must be used with WDD and may be used with other register content codes for the night period. Record day consumption during weekends. Non-seasonal equivalents of SWED and WWED (Summer and Winter weekend daytime).
Winter	W	Records consumption during winter.
Winter Day	WRD	Records day consumption during winter
Winter Night	WRN	Records night consumption during winter
Winter Weekday	WWD	Records consumption during winter weekdays.
Winter Weekday Day	WWDD	Records day consumption during winter weekdays.
Winter Weekday Night	WWDN	Records night consumption during winter weekdays.
Winter Weekend	WWE	Records consumption during winter weekends.
Winter Weekend Day	WWED	Records day consumption during winter weekends.
Winter Weekend Night	WWEN	Records night consumption during winter weekends.

Table 21: Grandfathered Register Content Codes

Tariff Type	Register Content Code	Description	Comment
Controlled	CN	All load on the channel is subject to control by the distributor at any time via a load control device.	Use of CN is grandfathered for fully controlled at fixed times, night only, and night boost metering installations (for example, CN8 and CN11) until the next recertification. All new and recertified night-only and night boost metering installations to use NO or NB (as appropriate).
Day	D	Only to be used with N. Daytime of an uncontrolled 2-channel day/night meter, switched between channels at fixed times via an internal time clock or external signal.	Use of N on its own is grandfathered for fully controlled at fixed times, night only, and night boost metering installations (for example, N8 and N11) until the next recertification. All new and recertified night-only and night boost metering installations to use NO or NB (as appropriate).
Night	N	Only to be used with D. Night-time of an uncontrolled 2-channel day/night meter, switched between channels at fixed times via an internal time clock or external signal.	
Day Off-peak	DOP	Triple Saver Off-Peak (11:00-17:00,21:00-23:00)	Use of this combination is grandfathered for existing metering installations until the next recertification Use generic codes for all new or recertified metering installations
Day Peak	DPK	Triple Saver Peak (07:00-11:00,17:00-21:00)	
Night	N	Night 23:00-07:00	

Tariff Type	Register Content Code	Description	Comment
Summer evening – night, weekdays	SENW	Weekday night (Monday – Friday 21:00 - 07:00); and all weekend (Friday 21:00 - Monday 07:00)	Use of these codes is grandfathered for existing metering installations until the next recertification. Use generic codes for all new or recertified metering installations.
Summer evening off-peak	SEOP	Off-peak (Monday - Friday 11:00 - 17:00; and 19:30 - 21:00)	
Summer evening peak	SEPK	Peak (Monday - Friday 07:00 - 11:00; and 17:00 - 19:30)	
Summer Workday Peak	SWDPK	Standard 3 Rate Summer Weekday Peak (07:00-11:00, 17:00-21:00)	Use of this combination of codes is grandfathered for existing metering installations until the ICPs are moved from the closed price category to a different price category, or the combination is no longer required.
Weekday Off-Peak	WDOP	Standard 3 Rate Weekday Off-peak (11:00-17:00, 21:00-23:00) & Weekend Off-peak (07:00-23:00)	
Winter Weekday Peak	WWDPK	Standard 3 Rate Winter Weekday Peak (07:00-11:00, 17:00-21:00)	
Night	N	23:00-07:00	
Off-peak weekdays	OPKOOB	Weekdays 11:00 - 17:00, 21:00 7:00 & Weekend 24 Hours. Must be used with PKOOB.	Grandfathered— Use of these codes is grandfathered for existing metering installations until the next recertification. Use generic codes for all new or recertified metering installations.
Peak weekdays	PKOOB	Weekdays 07:00 - 11:00 & 17:00 -21:00. Must be used with OPKOOB	

Tariff Type	Register Content Code	Description	Comment
Off-peak any day	OPKOOC	Any day 22:00 - 07:00. Must be used with PKOOC and SPKOOC.	Grandfathered— Use of these codes is grandfathered for existing metering installations until the next recertification. Use generic codes for all new or recertified metering installations.
Peak weekdays	PKOOC	Weekdays 07:00 - 09:30 & 17:30 - 20:00. Must be used with OPKOOC and SPKOOC.	
Shoulder Peak weekdays	SPKOOC	Weekdays 09:30 - 17:30, 20:00 - 22:00 & weekend 07:00 - 22:00. Must be used with OPKOOC and PKOOC.	

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