Horizon Networks

Pricing Methodology

For pricing introduced on 1 April 2023

31 March 2023

Disclosure of Pricing Methodology

Pursuant to Electricity Distribution Information Disclosure Determination 2012

Contents

1. Glossary

AMD	Anytime Maximum Demand
COS	Cost of Supply
DER	Distributed Energy Resources
DG	Distributed Generation
DPP	Default Price-Quality Path
DRC	Depreciated Replacement Cost
EDB	Electricity Distribution Business
EIEP	Electricity Information Exchange Protocols
GST	Goods and Services Tax
GXP	Grid Exit Point
HV	High Voltage
ICP	Installation Control Point
kVA	Kilowatt Ampere
kW	Kilowatts
kWh	Kilowatt Hour
LRR	Loss Rental Rebates
LV	Low Voltage
NMD	Network Maximum Demand
NZ IAS	New Zealand Equivalent to International Accounting Standard
RC	Replacement Cost
RCPD	Regional Co-incident Peak Demand
TOU	Time of Use
TPM	Transmission Pricing Methodology
WACC	Weighted Average Cost of Capital

2. About Horizon Networks

2.1. Introduction

Horizon Energy Distribution Limited (“Horizon Networks”) sets out in this document the methodology for setting prices effective 1 April 2023 (i.e. 2023/24 prices).

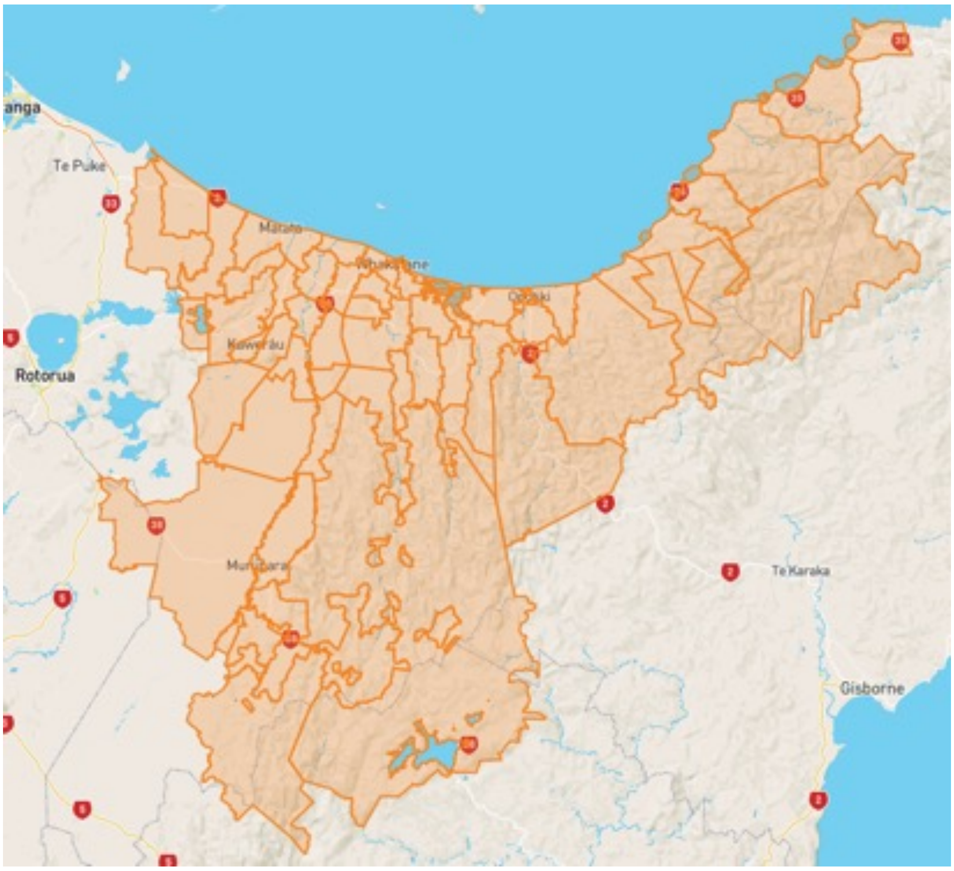
This Pricing Methodology is published pursuant to the requirements of the Electricity Information Disclosure Determination 2012.

2.2. Network Overview

Horizon Networks supplies electricity to more than 25,000 customers across Eastern Bay of Plenty covering the Whakatane, Opotiki and Kawerau regions. Electricity is drawn from three Grid Exit Points (GXPs) and one embedded generator situated in Aniwhenua.

The area of supply covers 8,400 km^2 and are bounded by Otamarakau to the West, Cape Runaway to the East, and Lake Rotoma, Kaingaroa and Ruatahuna to the South.

Horizon Networks is 100% locally owned by Trust Horizon, formerly known as the Eastern Bay Energy Trust. Trust Horizon invests in important projects in the region and are committed in driving the region forward to the benefit of consumers. The Trust is community owned.



Network coverage map

2.3. Network Context

The network is comprised of lines, transformers, switchgear and other assets required to deliver electricity from the national grid to end consumers. Horizon Networks' asset management strategy supports the provision of network services at a standard which reflects consumer price and quality expectations. Asset management includes operations, maintenance and periodic investments in new assets to ensure a safe and reliable electricity supply.

Pricing aims to ensure efficient recovery of network expenditure. These costs are shared across consumers, who generally benefit from economies of scale in the form of lower costs than they would have otherwise, through allocations of costs to consumer groups or service offerings.

Economically efficient prices should also signal the future cost impact of consumer use of the network. Use of network capacity required to meet peak demand is a key driver of future network costs. Demand and connection growth will drive investments in new capacity over time.

Connection density, reflecting the length of lines required to serve a regional grouping of connections, is another key driver of costs. Horizon Networks have previously determined that there is a difference in the cost of serving consumers in low density rural areas and higher density urban centres.

Set out below is a summary of the outlook for the key cost drivers of connections growth, demand growth and quality of supply.

2.3.1. Connections growth

Population increases in the Eastern Bay of Plenty are expected to be low over the next 30 years. This is reflected in Horizon Networks' relatively low connections growth forecast across the network of around 206 connections per annum (0.8% pa).

2.3.2. Demand growth

There are several demand related challenges that are relevant to pricing, including:

- Localised peak demand growth driving investment in specific areas; and
- Managing the uptake of DG such as solar on the network, and the potential impact on our cost to serve.

Demand is forecast to grow on average at 2% per year for the next 5 years.

	2022	2023	2024	2025	2026	2027
Maximum coincident demand (MW)	97	99	100	102	104	106

Table 1: *Demand Forecast*

Although growth is low across the network as a whole, there are areas of higher load growth across the network. For example, potential step changes in industrial loads are expected in some areas, particularly around Whakatane and Opotiki as results of development funded under the provincial growth fund, increased solar farm connections and businesses seeking to decarbonise. There is also the risk of industrial consumers disconnecting due to economic and commercial conditions, in which case there could be a fall in demand.

Set out below is the expected load growth across substations out to 2030.

Substation	Peak Demand (MVA)				
	2022	2026	CAGR (vs 2022)	2032	CAGR (vs 2022)
East Bank	5.3	6.3	4.42%	6.3	1.75%
Plains	8.6	8.9	1.00%	9.5	1.00%
Kope	16.5	16.7	0.20%	16.9	0.20%
Station Road	9.8	10.2	1.03%	10.8	1.03%
Ohope	4.9	5.2	1.46%	5.6	1.46%
Waiotahi (11kV GXP)[22]	13.0	14.5	2.75%	17.0	2.70%
Kawerau (with embedded generation)	-11.9	-11.9	0.00%	-11.9	0.00%
Kawerau (without embedded generation)	13.1	13.1	0.00%	13.1	0.00%
Galatea	4.7	4.7	0.01%	4.7	0.01%
Kaingaroa	2.6	2.6	0.00%	2.6	0.00%
Te Kaha	1.7	1.8	1.70%	1.9	1.26%

***Table 2:** Substation Demand Forecasts*

[22]*Waiotahi load assuming no load shift to Opotiki*

Expenditure is mostly related to ensuring assets continue to operate consistent with their service potential. Accordingly, there is a role for signalling the costs of meeting future additional demand in the foreseeable future.

2.3.3. Quality of Supply

Quality of supply means being able to maintain power quality and reliable supply to customers. Horizon Networks' aim is to maintain an acceptable quality of supply, and here possible improve reliability, without raising prices.

Horizon Networks experiences adverse weather events which can lead to a large impact on quality of supply. However, these are abnormal events and do not represent degradation of the network.

Horizon Networks' quality of supply strategy is consistent with the asset management plan and reflects customer needs. The quality of supply strategy influences how Horizon Networks achieves its network performance and continual improvement objectives.

3. Pricing Roadmap

3.1. Strategy

3.1.1. Horizon Networks incremental approach to pricing

Horizon Networks' pricing strategy is to pursue an incremental approach to pricing. An incremental approach reviews and refines prices regularly with the goal of ensuring prices align closely with the quantifiable cost of serving different customer groups.

This includes:

- Regularly reviewing and rebalancing charges between urban and rural customers
- Increasing the fixed price portion in all load groups, to reflect the fixed costs consumers face to receive supply; and
- Transitioning medium-sized commercial customers to (N4/N5) to NMD prices over time.

In 2022 Horizon Networks reviewed and updated its pricing structures to provide greater transparency and improved consumer choice. Since April 2022 Horizon Networks has offered time of use (TOU) pricing to domestic and standard consumers on an opt-in basis. This TOU pricing can be determined in a way that reflects the economic value to Horizon Networks in consumers shifting load away from peak periods.

In 2023 Horizon Networks reviewed and refreshed its approach to the pass through of transmission charges under the new Transmission Pricing Methodology (TPM). This has impacted the allocation of charges to consumers, particularly large consumers that historically were able to avoid interconnection charges through shifting load outside of transmission peak periods.

3.1.2. Horizon Networks forward-looking approach to pricing

There are a number of external changes affecting distribution pricing which Horizon Networks will need to consider how best to address over the over the next 5 years.

These include:

- The transition of domestic consumers away from the low fixed charge tariff, consistent with the governments five-year transition arrangements
- The impact of increased electrification and its impact on any network congestion, actions to remediate congestion and price signals to alleviate congestion
- The impact of increasing concentration of distributed generation on the costs to operate and maintain the network
- The impact of large-scale distributed generation on distribution pricing
- Any changes to the regulatory settings and technology that could impact pricing for distribution services, such as peer-to-peer trading, controllable load or use of non-network alternatives.

Horizon Networks continues to monitor the effectives of its existing pricing structures, including the uptake of TOU Pricing introduced in 2022, the impact of increasing the low fixed charge tariff has on consumer numbers and the current zero-charge tariff for distributed generation. This monitoring informs our pricing review process and allows us to amend price signals as necessary.

This forward-looking approach forms part of Horizon Networks wider strategy to iteratively review and refine pricing in response to anticipated and identified needs.

3.2. Horizon Networks pricing changes since 2021

Since the 2021 pricing road-map Horizon Networks has:

- Implemented an optional TOU pricing tariff for both standard and low fixed charge consumers
- Refined its transmission charges allocation methodology to align with the new transmission pricing methodology (TPM)
- Clarified:
  - The eligibility criteria for standard user and low user price categories to consider residential 3-phase connections
  - That NMD calculations are based solely on demand
  - The eligibility criteria for NMD and general capacity groups.

3.2.1. TOU pricing tariff

Following extensive consumer engagement and analysis, "Opt-in" TOU pricing was implemented in April 2022 for domestic consumers. TOU pricing can be a more cost-reflective pricing structure because it seeks to align the recovery of investments in network capacity with consumption at peak times.

TOU pricing helps consumers make informed decisions about when to use electricity.

While the network is not currently experiencing significant load congestion at present, TOU pricing helps us reflect the cost to serve domestic consumers, and to respond quickly to changes in network demand. An "opt in" approach enables retailers to offer consumers choice.

Since April 2022 three retailers have begun offering TOU pricing to residential consumers.

Uptake as of November 2022 was 0.3% of residential ICPs. It is too early to judge the level of retailer and consumer engagement with this pricing structure and Horizon Networks will continue to monitor and review uptake as part of its short-term roadmap.

The weak price signal of current TOU pricing in the domestic customer group can help consumers become familiar with the pricing structures and help normalise customers attitudes to the option ahead of any future, stronger price signal.

Those willing to adjust their demand in response to price changes have an opportunity to benefit from this and Horizon Networks will have the ability to understand how TOU implementation may affect future network investment.

3.2.2. Transmission charge allocation

The new transmission pricing methodology (TPM) is in place from 1 April 2023.

Changes include:

- Replacing the regional coincident peak demand (RCPD) allocator with a benefit-based allocator and residual allocator for non-standard customers
- Ending avoided cost of transmission (ACOT) payments to generators
- Ending the existing prudent discount agreements.

Horizon Networks has updated its transmission charge allocators to better align with the new TPM, replacing the RCPD allocator with an anytime maximum demand (AMD) allocator for non-standard customers, improving alignment with the allocation methodology for standard customers. See Section 5.1.3

The AMD allocator is designed to quantify the peak usage of the grid and allows Horizon Networks to equitably allocate fixed transmission charges via a fixed price to consumer groups based on their peak usage of the grid.

3.2.3. Clarifications to existing pricing structure

Horizon Networks has reviewed its pricing methodology to reduce ambiguity around eligibility criteria. This forms part of Horizon Networks annual process to review and refine the pricing methodology over time to ensure it remains clear and fit for purpose.

Clarifications added in this iteration of the pricing methodology include:

- Clarifying the eligibility criteria for each price category, including when there are 3-phase residential connections
- Clarifying that NMD is based on maximum demand.

3.3. Future Pricing Roadmap

Horizon Networks forward-looking, iterative approach to distribution pricing will improve responsiveness to a changing physical and regulatory environment.

This approach allows for a ‘review, assess, implement’ approach within the pricing year.

3.3.1. Short-term roadmap

Horizon Networks short-term roadmap is designed to test and incrementally improve the efficiency of existing pricing signals to inform incremental improvements for the 24/25 pricing year.

Key milestones for the next 12 months are:

Action	Outcome action supports
Review distribution pricing scorecard to assess areas for improvement	Efficient distribution pricing and alignment with regulatory expectations
Review transmission pricing pass-through allocators	Efficient pass-through of transmission charges
Review influence of distributed generation on distribution investment and costs to operate the network	Allocation of incremental costs (if any) to distributed generation
Review uptake of TOU tariff and effectiveness of pricing signals on consumer behaviour	Signalling avoidable costs in pricing
Ongoing transition of N4/N5 customers to other tariffs	Consistent distribution pricing

Table 3: *Horizon Networks Short Term pricing milestones*

3.3.2. Long-term roadmap

Horizon Networks long-term roadmap considers the wider operating environment under which prices will be set in the future, including changes in consumer attitudes, technology, regulations and how retailers pass through pricing signals.

The timing of many of these changes, if they are to occur is uncertain, so will be monitored over the next five years.

Action	Outcome action supports	Estimated Date
Review residential pricing structure following phase-out of low fixed charge regulations	Efficient distribution pricing and alignment with regulatory expectations	April 2027
Assess impact of electrification on price signals for congestion, including use of controlled load	Signals avoidable costs	2025 - 2030
Review if pricing for DER and non-network alternatives necessary	To signal quantifiable distribution benefit provided by DER and new technology.	2025 – 2030
Review customer groupings, including rural/urban split	Efficient allocation of distribution charges to consumer groups	2025 – 2027
Power Factor Pricing, investigate implementing Power Factor (PF) pricing for PF below 0.95 lagging, to improve efficiencies on the network and investment decisions	Signals avoidable costs to consumers	2025 – 2027
Updates due to distribution pricing reform	Efficient distribution pricing and alignment with regulatory expectations	2025 – 2030

Table 4: *Horizon Networks Long Term pricing milestones*

Long term actions are expected to result in more significant changes to the structure of distribution pricing. These types of changes are expected to require a consumer-centric view to achieve the necessary outcomes and will likely involve consumer engagement, in a similar way to the structural changes that resulted from the introduction of domestic TOU pricing.

4. Regulatory Considerations

Horizon Networks' Pricing Methodology is consistent with the following regulations:

- The Commerce Commission's *Electricity Distribution Information Disclosure Determination 2012* (IDD2012), set under Part 4 of the Commerce Act 1986 ("the Act");
- The Electricity Authority's 2022 *Distribution Pricing: Practice Note*;
- The Electricity Authority's *Low Fixed Charge Tariff Option for Domestic Consumers Regulations 2004* and *Low Fixed Charge Tariff Option for Domestic Consumers Amendment Regulations 2021* (the low fixed charge regulations); and
- *Part 6 of the Electricity Industry Participation Code* ("the Code"), relating to the pricing of DG.

The key requirements of these regulations are summarised below. Horizon Networks has developed and disclosed a Pricing Methodology consistent with these regulatory requirements.

4.1. Information Disclosures

Clause 2.4.1 to 2.4.5 of the IDD2012 sets out the requirements for disclosure of pricing methodologies. Horizon Networks is required to disclose a Pricing Methodology before the start of each pricing year which describes the methodology for setting prices and any changes that have occurred.

Further information on these requirements is provided in Appendix A.

4.2. Pricing Principles

The Pricing Principles referred to in clause 2.4.3(2) of IDD2012 were initially developed by the Electricity Commission in 2010 (and adopted by the Electricity Authority). The Electricity Authority (Authority) updated the Pricing Principles in 2019 and has recently provided updated guidance on how to apply these in practice.

Adoption of the Pricing Principles is voluntary, but EDBs must disclose the extent to which their pricing methodologies are consistent with the principles. Section 11 outlines how Horizon Network's Pricing Methodology aligns to the Pricing Principles.

The Authority has supplemented the Pricing Principles and guidance by providing an annual pricing score card, which outlines the Authority's views on each EDB's pricing. Horizon Networks' 2021 pricing scorecard has highlighted the appropriateness of a high proportion of fixed charges and a weak peak usage signal, given the limited growth on the network. It also has signalled the need to review how pricing will pass through transmission charges as the new Transmission Pricing Methodology is implemented. Consideration is given to this feedback in Section 11.

4.3. Low Fixed Charge Regulation phase-out

Under the low fixed charge (LFC) regulations, distributors are required to offer a pricing plan to domestic consumers in which the distributor's daily fixed charge must not exceed specific the thresholds in the table below.

Maximum low fixed charge	
Prior to 1 April 2022	$0.15 a day
1 April 2022	$0.30 a day
1 April 2023	$0.45 a day
1 April 2024	$0.60 a day
1 April 2025	$0.75 a day
1 April 2026	$0.90 a day
1 April 2027	Regulations removed. EDBs companies are no longer required to offer customers a low fixed charge.

Table 5: *Low fixed charge phase-out pricing*

These regulations are being phased out and will be removed from 1 April 2027.

For the 2023/2024 pricing year, starting 1 April 2023 the maximum daily fixed charge for distribution services is $0.45 a day.

A large proportion of the transmission and distribution costs faced by Horizon Networks do not change with changes in residential demand so are most efficiently recovered by a daily fixed charge. Horizon Networks will continue to annually increase the maximum low fixed charge in line with the phase-out provision in the regulations until it reaches parity with standard users in 2027.

Horizon Networks has processes in place to identify retailers incorrectly requesting a switch to an LFC price option.

4.4. Distributed Generation Pricing Principles

Part 6 of the Code sets out requirements for the connection of distributed generation (DG) to electricity distribution networks. It details a regulated connections process as well as regulated terms and conditions that will apply should parties fail to agree to an alternative connection contract.

The regulated terms for connection of DG require that connection charges payable by a distributed generator must be determined in accordance with Pricing Principles set out in Schedule 6.4. Clause 2 of Schedule 6.4 requires distributors to set prices based on reasonable costs to comply with connection and operation standards within the network, including consideration of any identifiable avoided costs (clause 2 of Schedule 6.4). Additionally, clause 2(a) of Schedule 6.4 sets a price cap at the incremental cost of connecting DG, net of any avoided costs that an efficient market operation service provider would be able to avoid as a result of the connection of the DG.

5. Pricing Methodology Overview

Horizon Networks undertakes the following steps to develop the Pricing Methodology and the associated line prices:

- Determine the amount of revenue to be recovered via line prices over the pricing period, in this case 1 April 2023 – 31 March 2024 (Section 5.1);
- Consider how to group consumers into load groups for pricing purposes, and determine the key attributes of each load group, for the purpose of allocating the revenue requirement and calculating prices (Section 6);
- Allocate the revenue requirement to load groups (Section 9); and
- Determine the structure of prices to apply to each load group for the pricing period (Section 10). Horizon Network's approach has not changed from 2022 when Opt-in TOU pricing for domestic customers was introduced.

The sections below outline the approach to each of these steps above.

5.1. Target Revenue

This section describes how Horizon Networks establishes the target revenue requirement to be recovered through lines prices.

5.1.1. Regulatory Limitations

Horizon Networks is subject to the Default Price-Quality Path (DPP) regulation under Part 4 of the Act. The Commerce Commission reset the DPP on 27 November 2019 for the period 1 April 2020 to 31 March 2025 in the Electricity Distribution Services DPP Determination 2020.

The total target revenue requirement for 2023/24 is determined on the basis of the maximum allowable revenue (MAR) Horizon Networks may recover from lines prices consistent with the DPP Determination 2021.

5.1.2. Target Revenue Requirement

Table 6 provides a breakdown of the 2023/24 target revenue requirement for electricity lines services. The target revenue requirement is exclusive of GST.

Cost Item	Revenue Requirement ($000)
Connection Charges	1,625
BBI and Residual Charges	5,625
Other Recoverable Costs	2,605
Electricity Authority Levies	132
Commerce Act and FENZ Levies	65
Local Body Rates	289
Business Support	3,733
System Management and Operations	3,693
Service interruptions and emergencies	1,139
Vegetation management	1,002
Routine and corrective maintenance and inspection	1,325
Asset replacement and renewal	443
Depreciation on Network Assets	6,065
Depreciation on Non-Network Assets	383
Pre Tax Return on Assets	7,690
Total Revenue Requirement	**35,814**

Table 6: *Revenue Building Blocks (Before Tax)*

The above revenue requirement of $35.8m consists of distribution revenue of $25.4m and pass-through revenue of $10.4m. This is inclusive of allowable recoverable costs and pass-through costs. The comparable revenue requirement for 2022/23 was $32.9m.

5.1.3. Recoverable Transmission charges

Recoverable costs that may be recovered through lines prices under the DPP include Transpower charges. The target revenue requirement includes forecasts of Transpower charges, including connection, benefit-based investments (BBI) and residual charges.

- **Connection charges** recoup Transpower's costs associated with connection assets built to connect the network to the national grid. These charges are generally attributable to the physical assets supplying Horizon Networks.
- **BBI charges** recoup Transpower costs for specific, grid investments in proportion to the benefit they provide each grid connected party. BBIs are set at the time the investment is planned and the calculation of BBIs is regulated by the Electricity Authority.
- **Residual charges** recover Transpower's remaining revenue that is not recovered through other transmission charges. Residual charges are paid, in proportion to gird connected parties historic maximum gross demand.

Horizon Networks passes through Transmission charges to consumer groups using the anytime maximum demand (AMD) allocator.

Loss rental rebates are excluded from the revenue requirement as these are passed directly to retailers and contracted customers, so do not impact line prices.

Loss rental rebates are credited on a monthly basis, against each retailer and contracted customers charges in the month following receipt of the rebate from Transpower.

Loss rental rebates are allocated in proportion to the total transmission charges faced by each retailer and contracted customer. For example, if a retailer or contracted customer faced 5% of the total transmission charges for the month, they will receive 5% of the loss rental rebate for that month.

Given the complexity of the wash-up process (where any reallocation of loss rental rebates impacts all customers) and fixed nature of the transmission charges allocator Horizon Networks does not intend to wash-up loss rental rebates.

5.1.4. Regulatory levies and local body rates

The various regulatory levies and local body rates are passed through directly to consumers using an annual consumption (kWh) allocator.

5.1.5. Operating, maintenance and administrative costs

Annual operating, maintenance and administration costs reflect the forecast, budgeted costs for providing lines services for the pricing period.

More information on these forecasts can be found in Horizon Networks asset management plan (AMP). It is possible for the AMP and pricing forecasts to differ, as the AMP will always use the most up to date information, while pricing is set earlier, using the latest information available at the time.

5.1.6. Depreciation

The depreciation component of the revenue requirement reflects the return on capital investment in network and non-network assets required in the provision of electricity lines services. The depreciation charge is calculated from Horizon Networks financial reporting asset values which have been stated at valuation, being the fair value at the date of revaluation, less any subsequent accumulated depreciation, in accordance with NZ IAS 16.

5.1.7. Return on assets

The return on asset component is calculated as the 2023/24 DPP allowable revenues set by the Commerce Commission less other expenditure. The Commerce Commission has set a target return on the asset base, using the 67th percentile estimate of vanilla WACC at 4.57% for the 2020-25 regulatory period.

6. Consumer Groups

6.1. Disaggregation of Load Groups

The Pricing Methodology seeks to fairly allocate costs amongst various consumer groups. Horizon Networks has chosen to separate consumers groups into load groupings in recognition of each group's respective network capacity utilisation. Network capacity is the primary service that EDBs provide and is a key driver of network costs. Consumer groupings based on typical consumer load profiles therefore align pricing to Horizon Network's costs and the service provided.

Load group disaggregation has been determined after consideration of the end use characteristics, location and capacity requirements of each connection. All connections are able to be classified by their service main fuse, selected from a range of national standard sizes. Consumers are also classified into capacity groups, with:

- Small capacity consumers being classified as either residential low users or a standard user group that contains both small businesses and larger residential consumers; and
- Larger capacity consumers are classified as general, network maximum demand, non-metered supplies or major consumers.

6.1.1. Urban and rural load groups

For pricing purposes, Horizon Networks distribution network has been segregated into urban and rural regions. The urban areas are the towns and built up areas of Kawerau, Edgecumbe, Whakatane and Opotiki. The rural areas make up the balance of the network. The boundaries, determined previously, have been retained to avoid unnecessary disruption to consumers and to minimise transaction costs.

The distinction between urban and rural networks is used for those components of Horizon Network's Pricing Methodology where the customer and network characteristics indicate that differential costs, and therefore price levels, are required to reflect fair prices to all consumers.

This distinction results in separate urban and rural pricing for domestic, capacity and NMD consumers.

Price codes can be easily identified as urban and rural through the last letter in the price code. U is used for urban price codes and R is used for rural price codes.

6.1.2. Small capacity load groups

Small capacity residential and commercial consumers have been grouped together because they share similar network usage profiles. Typically, the load profiles indicate peak consumption from 7:00am - 10:00am and 5:00pm - 9:30pm. In addition, it is necessary to distinguish between those domestic consumers within this load group which are subject to the low user fixed charge regulations. As the low user fixed charge regulations only apply to primary residences, domestic consumers are allocated into one of the following consumer groups:

- Low User Domestic –
  - Consumers primary residence, eligible under the low fixed charge regulations. This consumer group is typically targeted towards domestic consumers using less than 8,000 kWh per annum; and
- Standard User –
  - All domestic consumers; and
  - Small business consumers who use less than a 3 phase 60 Amp supply, where the consumer is not eligible for the low fixed user price.

6.1.3. Non-domestic capacity load groups

In contrast, non-domestic consumers exhibit a wide range of load profiles due to the diverse nature of their requirements. It is more practical to distinguish and charge these consumers by their load usage given the availability of data. These consumers are grouped together based on their assessed capacity requirements using their installed fuse rating or assessed installed transformer capacities. This approach reflects the fact that increased capacity requirements impose a greater demand on network assets.

Note: Capacity Group N4 and N5 prices are no longer available to new connections and existing customers are expected to move to NMD prices over time. Any ICP in these categories will be migrated on review to the NMD price category when capacity is altered in any form; inclusive of the addition of solar photovoltaic, therefore customers do not face an overlap in the choices available

6.1.4. Non-domestic network maximum demand

Non-domestic consumers with a connection size of greater than 70 kVA are grouped as Network Maximum Demand ("NMD") consumers (with the exception of those who have not yet transitioned away from capacity group N4 or N5). NMD customers are metered on maximum demand to assess individual capacity requirements which enables capacity-based pricing.

Horizon Networks also groups all non-domestic consumers which are unmetered (including street lighting and electric fence units) into an 'other' load group.

Additionally, since the 2022/23 year consumers in the Domestic pricing group, will have the option of being in a TOU category. This is discussed in further detail below.

A summary of Horizon Networks standard load groupings and key characteristics is provided in Table 7 below.

Description		Eligibility Criteria
Low User		
LUDU	Low User Domestic Urban	Residential consumer's primary place of residence.
LUDR	Low User Domestic Rural	
TOU LUDU	TOU Low User Domestic Urban	Residential consumer's primary place of residence. TOU pricing signals passed through to consumers.
TOU LUDR	TOU Low User Domestic Rural	
Standard		
NDU	Standard User - Urban	Residential consumer's primary place of residence **or** Commercial single phase connection with less than 14 kVA supply
NDR	Standard User - Rural	
TOU NDU	TOU Standard User - Urban	Residential consumer's primary place of residence **or** Commercial single phase connection with less than 14 kVA supply. Additionally TOU pricing signals passed through to consumers.
TOU NDR	TOU Standard User - Rural	

Description		Eligibility Criteria
Capacity Groups		
N2U	Urban Capacity Group 2 (15-42 kVA)	Non-residential connection. Connection size of between 15 and 42 kVA.
N2R	Rural Capacity Group 2 (15-42 kVA)	
N3U	Urban Capacity Group 3 (43-70 kVA)	Non-residential connection. Connection size of between 43 and 70 kVA.
N3R	Rural Capacity Group 3 (43-70 kVA)	
N4U	Urban Capacity Group 4 (71-100 kVA)	No longer available. Connection size of between 71 and 100 kVA.
N4R	Rural Capacity Group 4 (71-100 kVA)	
N5U	Urban Capacity Group 5 (>100 kVA)	No longer available. Connection size of between 71 and 100 kVA.
N5R	Rural Capacity Group 5 (>100 kVA)	
Network Maximum Demand		
NMDU	Network Maximum Demand Urban	Non-residential connection. Connection size greater than 70 kVA.
NMDR	Network Maximum Demand Rural	
Specials		
UV	U/Veranda Lights	No longer available.
EF	Electric Fence	No longer available.
SL	Street Lights	Non-residential dedicated streetlight connection
PCM 24	PCM 24 Hour	Non-residential dedicated telecommunication cabinet connection
PCMN	PCM Night Only	No longer available.

Table 7: *Standard Load Groups*

		Number of ICPs	Consumption (kWh)	AMD (kW)	Share of Total Assets (DRC%)
Domestic and Standard					
LUD	Low User Domestic	12,014	63,528,432	24,029	23.4%
TOU LUD	Low User Domestic TOU	121	641,701	243	0.2%
ND	Standard User	9,878	79,598,055	19,757	21.0%
TOU ND	Standard User TOU	100	804,021	200	0.2%
Capacity Groups					
N2U	Urban Capacity Group 2 (15-42 kVA)	832	13,236,593	4,992	4.0%
N2R	Rural Capacity Group 2 (15-42 kVA)	1,498	24,069,928	8,990	12.2%
N3U	Urban Capacity Group 3 (43-70 kVA)	267	10,430,282	4,539	3.6%
N3R	Rural Capacity Group 3 (43-70 kVA)	320	17,643,347	5,440	7.4%
N4U	Urban Capacity Group 4 (71-100 kVA)	34	1,958,212	1,020	0.8%

		Number of ICPs	Consumption (kWh)	AMD (kW)	Share of Total Assets (DRC%)
N4R	Rural Capacity Group 4 (71-100 kVA)	31	1,822,995	930	1.3%
N5U	Urban Capacity Group 5 (>100 kVA)	22	2,402,744	990	0.8%
N5R	Rural Capacity Group 5 (>100 kVA)	20	1,265,588	900	1.2%
Network Maximum Demand					
NMDU	Network Maximum Demand Urban	65	27,887,438	5,980	4.8%
NMDR	Network Maximum Demand Rural	116	30,123,924	10,672	14.4%
Specials					
UV	U/Veranda Lights	15	-	2	0.0%
EF	Electric Fence	5	-	1	0.0%
SL	Street Lights	15	2,326,429	375	0.9%
PCM 24	PCM 24 Hour	55	-	83	0.1%
PCMN	PCM Night Only	3	-	2	0.0%

Table 8: *Statistics Relevant to Load Groups*

The majority of this document addresses the Pricing Methodology for those consumers on standard contract terms. The methodology for setting prices for non-standard contracts and DG is described in detail in section 7 and 8 below.

7. Non-Standard Contracts

Horizon Networks has eight non-standard contracts with large consumers that have dedicated assets. The target revenue for non-standard contracts is $4.3 million. For commercial reasons, prices and revenue figures for individual contracts are not shown in detail.

Horizon Networks' minimum criteria for determining whether to enter into a non-standard contract include:

- Peak demand or generation above 1.5 MVA; or
- There is an existing non-standard contract up to be renewed.

7.1. Non-Standard Pricing Methodology

The methodology for determining prices for non-standard consumers follows a similar approach to that for standard contracts. A cost-based building block is calculated to determine prices applicable to each non-standard consumer.

Prices seek to recover the full cost of dedicated assets, including:

- A return of capital (i.e. depreciation);
- A return on capital (using a pre-tax weighted average cost of capital of 4.76%);
- Operations and maintenance;
- An allocation of shared asset costs (as above), which are apportioned to non-standard consumers based on their capacity utilisation of those assets;
- An allocation of transmission charges based on capacity utilisation (anytime maximum demand); and
- A share of general overheads, including rates and levies, based on an allocation of shared assets.

7.2. Specific Obligations to Non-Standard Consumers

Horizon Networks has a commitment to large customers to ensure supply is maintained within the agreed quality thresholds. These obligations and responsibilities are not substantially different to those of consumers on standard contracts.

When a large industrial customer requests higher reliability than a standard customer, there is typically a requirement for specific assets to be installed to achieve an improved service level. The large customer pays for the use of the extra assets in the normal way. This allows a transparent price versus quality trade-off to all parties.

8. Distribution Generation

Horizon Networks has a published policy on DG. This covers two sizes of DG; connections under 10kW and larger generation with capacity above 10kW. The policy covers:

- The connection process;
- Network charges;
- Technical requirements;
- Data requirements; and
- Useful links to further information.

The policy has been prepared in accordance with Part 6 of the Electricity Industry Participation Code 2010 (the Code), including the DG Pricing Principles and eligibility criteria for paying avoided transmission charges. Under these DG Pricing Principles Horizon Networks may charge no more than the incremental costs of connecting DG to the network, and include consideration of any identifiable avoided or avoidable costs.

8.1. Small scale generation

Over the past couple of years small solar generation without storage has been connected to the network. Horizon Networks does not receive any benefit from these units and therefore is not able to pass any benefits to the owners of this generation.

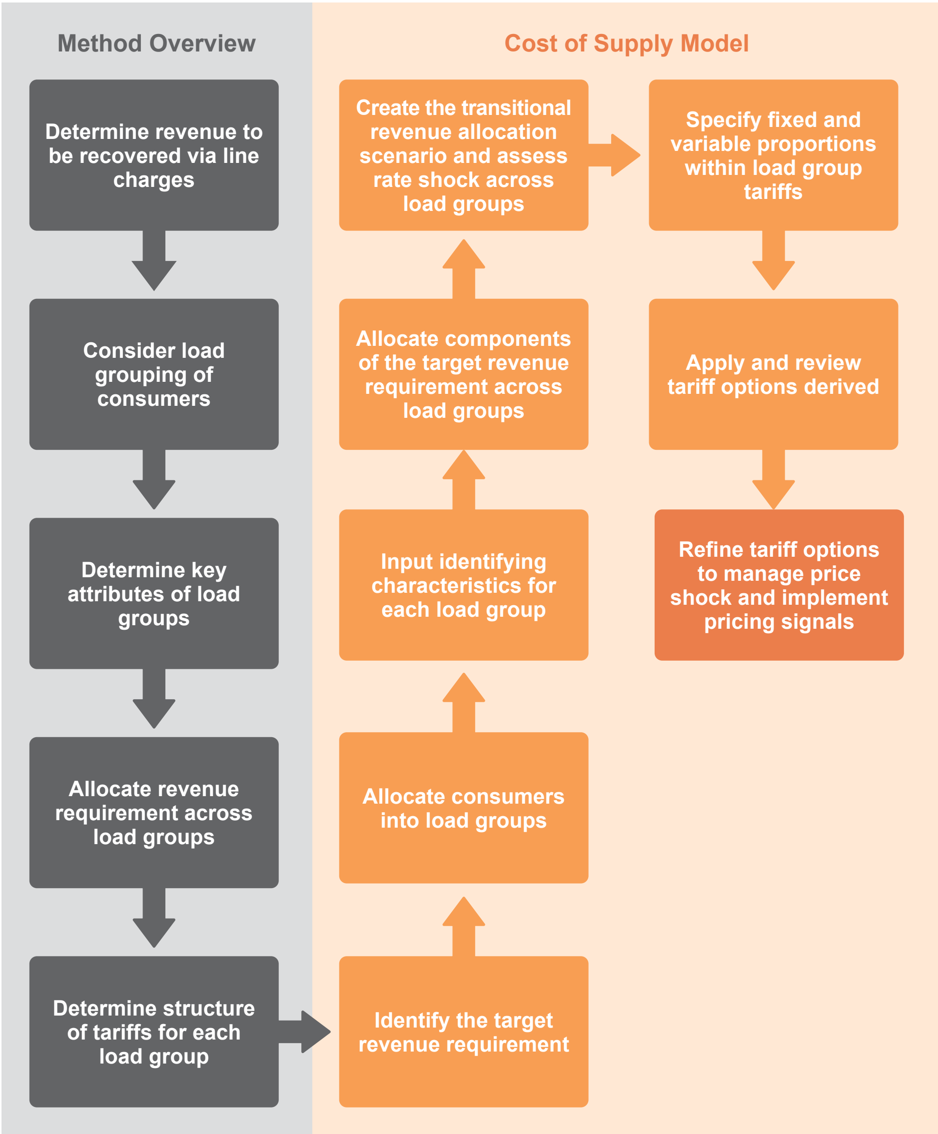
Line prices are attributed to both load and injection within the network. Any injection from DG will incur standard line charges attributed to the applicable consumer group.

In keeping with Horizon Network's DG policy and current Pricing Methodology, small scale DG price codes were introduced during the 2016/17 pricing year. These price codes enable retailers to provide billing and volume information to Horizon Networks at an ICP level to support the invoicing of variable line charges for small scale DG if and when it becomes required. The price applied for injection is currently set at $0/kwh, with Horizon Networks considering annually the need for a price .

Our DG pricing and connections policy is regularly reviewed, including to allow for the specific circumstances of large-scale Solar PV. Prices for larger DG will be determined based on the incremental costs associated with connecting them to the network, consistent with the Pricing Principles in Part 6 of the Code.

9. Revenue Allocation to Standard Load Groups

9.1. Overview of Pricing Process



9.2. Cost of Supply Model

Horizon Networks has developed a Cost of Supply (COS) model which separately allocates each component of the revenue requirement to load groups using appropriate cost allocators. The COS modelling process comprises the following key calculations:

- Identify the target revenue requirement to be recovered from line prices, by cost component as outlined above;
- Allocate consumers into load groups consistent with the existing load group structure discussed above;

- Input identifying characteristics for each load group (e.g. number of ICPs, kWh, etc.) which are used to allocate costs;
- Allocate each component of the target revenue requirement to the proposed load groups using cost of supply allocators (refer below) to determine the amount of revenue to be recovered from each load group;
- Derive a modified set of revenue allocations such that the revenue to be recovered from each load group is not materially different from the previous year, considering changes in customer numbers and consumption. This generates a transitional revenue allocation scenario which is used to analyse and manage potential rate shock for individual consumers;
- Once the revenue requirement for each load group is determined, specify the proportion of fixed and variable, distribution and transmission prices to test alternative price options;
- Apply the price options derived for each load group across consumption bands to test the impact on high/average/low use consumers within each load group; and
- Refine the price options as required to meet regulatory requirements, manage price shock and implement pricing signals consistent with the Pricing Principles.

9.3. Allocation of Target Revenue Requirement to Standard Load Groups

The target revenue requirement is specified across a number of different cost categories as outlined above. The COS model incorporates sufficient flexibility to allocate individual cost components to load groups using a range of applicable allocators. To some extent the range of allocators is limited by data availability and in some instances, proxies have been used.

The relevant allocators which are currently available to Horizon Networks are:

- ICP count;
- Load (kWh);
- AMD; and
- DRC[1] of System Fixed Assets ($).

Horizon Networks have allocated the components of the target revenue requirement using the cost allocators set out below in Table 9.

Cost Item	Revenue Requirement ($)	Cost Allocator
Connection Charges	1,625,360	Anytime Maximum Demand
BBI and Residual Charges	5,625,138	Anytime Maximum Demand
Other Recoverable Costs	2,604,700	Anytime Maximum Demand
Electricity Authority Levies	131,730	ICP Count
Commerce Act and FENZ Levies	65,330	Asset Related Allocator
Local Authority Rates	288,510	Asset Related Allocator
Business Support	3,733,370	ICP Count

Cost Item	Revenue Requirement ($)	Cost Allocator
System Management and Operations	3,692,960	Asset Related Allocator
Service interruptions and emergencies	1,139,407	Asset Related Allocator
Vegetation management	1,001,688	Asset Related Allocator
Routine and corrective maintenance and inspection	1,325,175	Asset Related Allocator
Asset replacement and renewal	442,840	Asset Related Allocator
Depreciation on Network Assets	6,065,252	Asset Related Allocator
Depreciation on Non-Network Assets	382,560	ICP Count
Target Pre Tax Return on Assets	7,689,960	Asset Related Allocator
Total Revenue Requirement	**35,813,980**	

Table 9: *Summary of Cost Allocators Used for Revenue Requirements*

[1]Depreciated replacement cost, Horizon Networks estimate of the fair value of the assets taking into account its remaining life.

This allocator selection demonstrates the underlying cost drivers for electricity supply, being the provision, operation and maintenance of network assets of a given service capacity. In recognition of this, Horizon Networks have selected allocators which best reflect the usage of assets and demand for capacity for each customer group. Similarly, transmission charges have also been allocated based on capacity utilisation. This reflects Transpower's requirement to provide adequate capacity (and maintain the availability of that capacity) in the national grid.

General management, administration and overhead costs, levies and non-network assets are allocated to load groups on the relative number of connections, recognising that these costs are shared by all consumers equally.

9.4. Information Used for Cost Allocators

The following information is used for the purpose of cost allocation.

9.4.1. ICP allocator

ICPs – The number of ICPs within each load group are used to allocate components of the revenue requirement which are deemed to be shared equally across all ICPs.

9.4.2. Load allocator

Load (kWh) – Annual consumption is an allocator which may be used to share components of the revenue requirement between load groups. Previously, this was applied to Loss Rental Rebate (LRR) revenues. However, under the current COS modelling assumptions, this is no longer used as all LRR revenues are to be passed on directly.

9.4.3. Anytime maximum demand allocator

AMD (kW) – Each load group's anytime maximum demand is used to allocate transmission charges, consistent with TPM which apportions residual transmission charge via historic maximum gross demand. This allocator reflects the local capacity required to supply various consumer groups, and as it considers each consumers peak use of the network, the use of AMD as an allocator does not disadvantage individual customers groups. The use of AMD as an allocator for all transmission charges is simple, effective and fair, and is reviewed regularly to ensure it remains relevant as the residual charge decreases.

9.4.4. Asset related allocators

The most recent financial reporting DRC valuation asset register is used for this purpose as this is the most recent asset register available with sufficient granularity. Assets are allocated into load groups as follows:

DRC is allocated into the following network components:

- Sub transmission;
- Zone substations;
- Distribution HV/LV; and
- Street lighting assets.

Assets dedicated to the major industrial consumers are extracted from the above asset groups.

Street lighting assets are allocated directly to the street lighting load group.

To allocate the non-dedicated assets between rural and urban network segments it is assumed:

- The sub transmission backbone including zone substation assets are shared equally across the entire network; and
- Distribution assets located in the urban and rural areas are dedicated to those consumers located in urban and rural zones respectively. To achieve this, all of the distribution assets are allocated into urban and rural zones by designating feeders as urban or rural. Locational identifiers from the fixed asset valuation are available for the purpose of ascribing all distribution assets to a feeder.

The sub transmission, zone substation, urban distribution and rural distribution assets are shared between urban and rural domestic, urban and rural capacity, NMD and special load groups on the basis of the anytime maximum demand of each load group.

Once the asset values are ascribed for each load group, the proportion of the depreciated asset value assigned to each load group is used to apportion asset related components of the revenue requirement (e.g. line maintenance, depreciation, and profit).

9.5. Revenue Requirement Allocation to Standard Load Groups

Using the methodology and assumptions outlined above, the revenue requirement for 2023/24 is allocated to load groups as set out in Tables 10 and 11.

Table 11 compares 2023/24 revenue allocations to previous 2023/23 revenue allocations.

Due to the phase-out of the low user regulations, Horizon Networks has updated its forecasts to reflect a gradual consumer shift from low to standard user pricing. As a result we expect more revenue to be recovered via standard users from an increasing standard user base, and comparatively less revenue to be recovered from a decreasing low user consumer base.

		2023/24 Revenue ($)	2022/23 Revenue ($)	Revenue Change ($)
Domestic				
LU	Low User Domestic	7,609,275	7,508,326	
TOU LU	Low User Domestic TOU	76,810	75,835	101,924
Standard				
ND	Standard User	8,647,816	7,656,828	
TOU ND	Standard User	87,425	77,363	1,001,050
Capacity Groups				
N2	Capacity Group 2 (15-42 kVA)	4,888,913	4,519,190	369,724
N3	Capacity Group 3 (43-70 kVA)	3,194,221	2,874,418	319,804
N4	Capacity Group 4 (71-100 kVA)	599,984	512,528	87,456
N5	Capacity Group 5 (>100 kVA)	577,895	503,786	74,109
Network Maximum Demand				
NMD	Network Maximum Demand	5,389,635	4,608,542	781,093
Specials				
UV	U/Veranda Lights	5,136	4,736	400
EF	Electric Fence	1,589	1,505	84
SL	Street Lights	358,824	344,852	13,972
PCM 24	PCM 24 Hour	43,933	42,710	1,223
PCMN	PCM Night Only	1,034	983	50

Table 10: *Allocation of Revenue Requirement to Price Groups*

Table 10 provides a detailed breakdown of cost allocations for each load group, by transmission and distribution components of revenue, for fixed and variable price type.

		Distribution Revenue ($)			Pass-through Revenue ($)			Total Revenue ($)
		Fixed	Variable	Total	Fixed	Variable	Total	
Domestic								
LUD	Low User Domestic	440,602	5,630,525	6,071,127	1,538,148	-	1,538,148	**7,609,275**
TOU LUD	Low User Domestic TOU	4,451	56,823	61,273	15,537	-	15,537	**76,810**
Standard								
ND	Standard User	4,466,361	2,254,217	6,720,578	1,927,238	-	1,927,238	8,647,816
TOU ND	Standard User TOU	26,858	41,100	67,958	19,467	-	19,467	87,425
Capacity Groups								
N2	Capacity Group 2 (15-42 kVA)	1,596,129	2,199,998	3,796,126	1,092,787	-	1,092,787	**4,888,913**
N3	Capacity Group 3 (43-70 kVA)	983,683	1,437,383	2,421,067	773,155	-	773,155	3,194,221
N4	Capacity Group 4 (71-100 kVA)	191,401	257,994	449,395	150,589	-	150,589	599,984
N5	Capacity Group 5 (>100 kVA)	200,872	231,164	432,035	145,860	-	145,860	577,895
Network Maximum Demand								
NMD	Network Maximum Demand	2,483,034	1,616,777	4,099,810	1,289,825	-	1,289,825	**5,389,635**
Specials								
UV	U/Veranda Lights	4,953	-	4,953	183	-	183	**5,136**
EF	Electric Fence	1,528	-	1,528	61	-	61	**1,589**
SL	Street Lights	327,975	-	327,975	30,848	-	30,848	**358,824**
PCM 24	PCM 24 Hour	37,295	-	37,295	6,638	-	6,638	**43,933**
PCMN	PCM Night Only	904	-	904	130	-	130	**1,034**

Table 11: *Allocation of Revenue Requirement (Detailed) to Load Groups*

9.6. Urban/Rural Differentiation

Special consideration has been given to the characteristics of connections located in urban and rural areas, and the different demands they make on the network. Connection density is a factor which influences differences in the costs of supply between urban and rural network locations. More investment is required in rural areas to provide the same connection capacity when compared to urban areas given the greater distances, on average between connections. However, connections located in urban areas are generally larger on average due to the higher intensity of non-domestic connections.

In addition, network configuration and shorter response times generally result in higher service quality in urban areas when compared to rural areas. This offsets in part the investment imbalance.

For the purpose of the 2023/24 Pricing Methodology the following approach has been adopted in respect of urban/rural price differentials:

- Transmission charges are the same for urban and rural consumers within each load group reflecting the fact that the transmission service delivery occurs up to the GXP, and thus is equivalent for all like customers irrespective of location on the distribution network;
- Distribution costs are allocated separately to urban and rural consumers for the domestic and general capacity load groups. NMD consumers are split into rural and urban categories but are currently allocated these costs as a single group. Large consumers have no rural/urban allocation as the price methodologies applied to consumers within these groups are specific to the characteristics of each individual consumer;
- For domestic consumers, the urban and rural prices are equalised. This occurs because of the constraints of the low fixed charge regulations and the requirement to maintain revenue equivalence with the cross over to the standard user pricing plan at 8,000 kWh. Urban and rural prices have been maintained and Horizon Networks plans to consider possible differentiation between rural and urban domestic prices in the future; and
- For general capacity consumers, urban and rural prices are implemented to recover the distribution component of the underlying costs for each network segment. The target revenue recovery is determined by the COS model (as outlined above) and the fixed and variable components of revenue are determined using the methodology outlined previously. This is the same underlying methodology as applied in previous years where urban/rural differentials have also been charged to general capacity consumers.

10. Pricing Structure

10.1. Key Considerations

Horizon Networks has developed its pricing structure upon consideration of the following relevant factors:

- The extent to which Horizon Networks underlying costs are fixed or variable;
- Mitigation of revenue risk associated with passing on transmission and avoided transmission charges;
- The impact of the low fixed charge regulations and the requirement to maintain a daily fixed charge and revenue equivalence based on kWh usage;
- The manner in which costs can be shared between low, medium and high-volume users within each load group;
- The existing pricing structures and the need to moderate step changes in any one pricing year;
- Appropriately signaling future investment costs through use of pricing structures that create incentives on consumers regarding incremental load, energy efficiency, demand management and capacity utilisation;
- A desire for transaction and pricing simplicity;
- The availability of information necessary to implement certain pricing options;
- Retailer pricing structures and the likelihood of retailers repackaging prices and passing through pricing signals;
- The likelihood of uneconomic bypass of the distribution system; and
- The service levels provided to different load groups.

10.2. Price categories

10.2.1. Horizon Networks approach to pricing has not changed from last year

The pricing approach adopted for 2023/24 has not changed from last year. In 2022/23 Horizon Networks started offering the option of TOU pricing for domestic consumers. The Electricity Authority considers that TOU pricing provides an actionable signal of network costs to consumers, particularly where network constraints occur consistently at a specific time. TOU prices are better than anytime consumption prices at signalling the economic cost of providing network services. Higher peak prices signal the cost of investments in network capacity to serve network peaks while lower off-peak and shoulder prices encourage use of the network when the cost to service is lower.

10.2.2. Transmission charges are recovered through fixed charges

As transmission charges (as a component of recoverable costs) are substantially known at the time prices are set, Horizon Networks removes revenue risk associated with the recovery of these external costs by passing these through to consumers as fully fixed charges (subject to low user regulation constraints and transitional arrangements).

10.2.3. Distribution charges are made up of a fixed charge and unit (kWh) charge

The distribution component of the revenue recovery for all load groups (with the exception of large and NMD consumers) comprises:

- A unit charge (c/kWh) recovered on the basis of electricity consumption and injection; and
- A fixed charge ($/day/ICP) recovered for every ICP within each load group on a consistent basis.

10.2.4. Horizon Networks continues to work towards a higher proportion of fixed charges, to reflect the fixed costs faced in running the network

The relative recovery of costs between fixed and variable charges reflects the trade-offs between compliance with the low fixed charge regulations, revenue risk, energy efficiency, contributions to incremental capacity, intergroup cross subsidy (between low and high users within each standard load group) and price simplicity. Over time, Horizon Networks will continue to increase the proportion of fixed charge revenue as the low fixed charge regulations are transitioned out and to align to our calculation of non-economic costs.

Horizon Networks rationale for a higher balance of fixed charges is that all consumers must contribute to the required cost recovery through the fixed charge component regardless of energy consumption. This recognises that the majority of Horizon Network’s network investments are sunk and fixed (i.e. having already been made and having no alternative use) and there is limited need to signal constraints on the network. Nevertheless, a variable element to pricing structures is seen as important for sending appropriate signals to consumers regarding the impact their usage has on future investment costs. It also better recognises relative usage of existing capacity by different load groupings. This is a key reason for Horizon Networks has implemented TOU pricing.

10.2.5. TOU Pricing

For TOU customers the part of the unit charge relating to consumption is broken down into peak, shoulder and off-peak periods. There is no TOU period separation by business and non-business day.

- Peak period is 7:00am – 11:00am, 5:00pm – 9:00pm.
- Shoulder period is 11:00am – 5:00pm, 9:00pm – 10:00pm.
- Off-peak period is 10:00pm – 7:00am.

These periods were determined from analysis undertaken on consumption data provided previously by retailers. We will continue to review consumption data and the appropriate TOU period definition as part of the ongoing refinement of this pricing.

10.2.6. NMD Pricing

For NMD consumers, a more sophisticated price structure (consistent with the 2022/23 price structure) is provided which better reflects the diversity of consumers within this price group and the ability (given the additional information available about these consumers) to price on a capacity and demand basis, as follows:

- A unit price ($/kWh) recovered on the basis of electricity consumption;
- A unit price ($/kWh) recovered on the basis of electricity injection, currently set at 0.0 $/kWh;
- A fixed price ($/kVA/day) recovered for every unit of installed capacity for each consumer; and
- A fixed price ($/kW) recovered for every unit of assessed peak demand for each consumer.

Peak demand is calculated initially for each individual consumer when they are connected to the network and assessed annually thereafter (based upon the historical RCPD year of Sept – August). Horizon Networks uses the Authority specified EIEP3 half-hour file to receive and process metering information on NMD consumers.

The demand portion is based on the higher of:

- Either 60% of the Capacity Charge (in kW); or
- The highest peak demand incurred in the preceding RCPD year (in kW). If monthly demands incurred indicate a ‘significant’ upward variation on the demand taken from the system, it may be adjusted upwards for the following months.

Where Horizon Networks has not received metering information in the prescribed half-hourly EIEP3 format or in an acceptable alternative format to determine maximum demand and Horizon Networks have insufficient information to determine the maximum demand, then the maximum demand for the consumer is assessed as 95% of the capacity requirement.

10.2.7. Revenue allocation across price categories

Revenue allocation across price codes is outlined for the TOU pricing in table 12a below and for existing price codes in table 12b.

Price Category	Price Component Code	Charge Type	Unit	Revenue %
Domestic				
TOU Low User Domestic	LUDU-TOU-FX / LUDR-TOU-FX	Fixed Daily Charge	ICPs	0.06%
TOU Low User Domestic	LUDU-TOU-OP / LUDR-TOU-OP	Consumption charge - off-peak	kWh	0.03%
TOU Low User Domestic	LUDU-TOU-SH / LUDR-TOU-SH	Consumption charge - shoulder	kWh	0.03%
TOU Low User Domestic	LUDU-TOU-PK / LUDR-TOU-PK	Consumption charge - peak	kWh	0.09%
TOU Low User Domestic	LUDU-TOU-DG / LUDR-TOU-DG	Export Charge	kWh	0.00%
Standard				
TOU Standard User	NDU-TOU-FX / NDR-TOU-FX	Fixed Daily Charge	ICPs	0.13%
TOU Standard User	NDU-TOU-OP / NDR-TOU-OP	Consumption charge - off-peak	kWh	0.02%
TOU Standard User	NDU-TOU-SH / NDR-TOU-SH	Consumption charge - shoulder	kWh	0.02%
TOU Standard User	NDU-TOU-PK / NDR-TOU-PK	Consumption charge - peak	kWh	0.07%
TOU Standard User	NDU-TOU-DG / NDR-TOU-DG	Export Charge	kWh	0.00%

Table 12a: *TOU price codes*

Price Category		Price Component Code	Charge Type	Unit	Revenue %
Domestic					
	Low User Domestic	HET001 / HET003	Fixed Daily Charge	ICPs	5.53%
	Low User Domestic	HET012 / HET013	Consumption Charge	kWh	15.72%
	Low User Domestic	HET112 / HET153	Export Charge	kWh	0.00%
Standard					
	Standard User	HET034/ HET054/ HET154	Fixed Daily Charge	ICPs	17.85%
	Standard User	HET035/ HET055/ HET155	Consumption Charge	kWh	6.29%
	Standard User	HET154 / HET155	Export Charge	kWh	0.00%
General - Urban					
N2U	Urban Capacity Group 2 (15-42 kVA)	HET017	Fixed Daily Charge	ICPs	1.89%
N2U	Urban Capacity Group 2 (15-42 kVA)	HET041	Consumption Charge	kWh	1.54%
N2U	Urban Capacity Group 2 (15-42 kVA)	HET141	Consumption Charge	kWh	0.00%
N3U	Urban Capacity Group 3 (43-70 kVA)	HET018	Fixed Daily Charge	ICPs	1.68%
N3U	Urban Capacity Group 3 (43-70 kVA)	HET042	Consumption Charge	kWh	1.38%
N3U	Urban Capacity Group 3 (43-70 kVA)	HET142	Consumption Charge	kWh	0.00%
N4U	Urban Capacity Group 4 (71-100 kVA)	HET019	Fixed Daily Charge	ICPs	0.47%
N4U	Urban Capacity Group 4 (71-100 kVA)	HET043	Consumption Charge	kWh	0.35%
N5U	Urban Capacity Group 5 (>100 kVA)	HET020	Capacity Charge (c/kVA/day)	KVA	0.46%
N5U	Urban Capacity Group 5 (>100 kVA)	HET044	Consumption Charge	kWh	0.31%

Price Category		Price Component Code	Charge Type	Unit	Revenue %
General - Rural					
N2R	Rural Capacity Group 2 (15-42 kVA)	HET023	Fixed Daily Charge	ICPs	5.62%
N2R	Rural Capacity Group 2 (15-42 kVA)	HET046	Consumption Charge	kWh	4.60%
N2R	Rural Capacity Group 2 (15-42 kVA)	HET146	Consumption Charge	kWh	0.00%
N3R	Rural Capacity Group 3 (43-70 kVA)	HET024	Fixed Daily Charge	ICPs	3.22%
N3R	Rural Capacity Group 3 (43-70 kVA)	HET047	Consumption Charge	kWh	2.64%
N3R	Rural Capacity Group 3 (43-70 kVA)	HET147	Consumption Charge	kWh	0.00%
N4R	Rural Capacity Group 4 (71-100 kVA)	HET025	Fixed Daily Charge	ICPs	0.49%
N4R	Urban Capacity Group 4 (71-100 kVA)	HET048	Consumption Charge	kWh	0.37%
N5R	Rural Capacity Group 5 (>100 kVA)	HET026	Capacity Charge (c/kVA/day)	KVA	0.51%
N5R	Rural Capacity Group 5 (>100 kVA)	HET049	Consumption Charge	kWh	0.34%
Network Maximum Demand					
NMD	Network Maximum Demand	HET074	Capacity Charge ($/kVA/mth)	KVA	3.76%
NMD	Network Maximum Demand	HET076	Demand Charge ($/kW/mth)	kW	6.77%
NMD	Network Maximum Demand	HET077	Consumption Charge	kWh	4.51%
NMD	Network Maximum Demand	HET177	Export Charge	kWh	0.00%
Specials					
UV	U/Veranda Lights	HET009	Fixed Daily Charge	ICPs	0.01%
EF	Electric Fence	HET006	Fixed Daily Charge	ICPs	0.00%
SL	Street Lights	HET131	Charge per streetlight	Lights	1.00%
SL	Street Lights	HET008	Consumption Charge	kWh	0.00%
PCM 24	PCM 24 Hour	HET115	Fixed Monthly Charge ($/mth)	ICPs	0.12%
PCMN	PCM Night Only	HET116	Fixed Monthly Charge ($/mth)	ICPs	0.00%
Non-standard Contracts	Large Consumers		Fixed Revenue		12.09%

Table 12b: *Non Time of Use price codes*

11. Distribution Pricing Principles

The following section provides a summary of how the Pricing Principles are reflected in this year's Pricing Methodology. The Authority has provided practical guidance in the form of a Practice Note[2] to assist distributors in applying the Pricing Principles, which has been considered in this response.

11.1. The 2019 Distribution pricing principles

Principle 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.

Principle 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.

Principle 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.

Principle D: Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives.

[2] *The October 2022 Practice Note is available from the Electricity Authority website.*

11.2. Pricing Principles

The process for determining line prices for non-standard consumers aligns with the Pricing Principles, as follows:

- Prices have been set to signal the economic cost of the service provided and are subsidy free within each consumer group. Prices are set greater than the avoidable cost of the assets in use because the costs of dedicated assets are recovered (that otherwise would be avoided if there was no connection) plus a contribution to shared assets. The standalone cost would require the customer to meet the full cost of each asset used to deliver supply and will, by necessity, be higher. This is perhaps best evidenced by the fact that even the largest non-standard consumers have accepted contractual terms, and not attempted to bypass the network to achieve a lower standalone cost.
- To the extent practicable, prices reflect the capacity requirements of major customers. This is because cost allocations are based on maximum demand drivers and capacity utilisation of shared assets.
- Non-standard prices implicitly signal the impact of additional usage on future investment costs. This is because negotiations centre on the provision of dedicated assets, capacity and coincident demand which provide a pre-specified level of service for a given price. Any requirement for additional capacity or service capability above that provided for in contracts will need to be recouped in renegotiated prices.
- Discussions held on pricing and willingness to pay as part of contract negotiations determines the demand responsiveness of non-standard consumers.
- Non-standard pricing is offered to some consumers partly to discourage uneconomic bypass. Discussions over price and quality trade-offs are also inherent in the use of non-standard contracts.
- Allowances have been made within non-standard pricing for DG, where applicable. For instance, one non-standard consumer is given a discount in recognition of its use of DG.
- Careful consideration is given to the impact on large consumers when setting prices, with the use of fixed pricing promoting certainty for large consumers. Pricing schedules are transparently provided to non-standard consumers and are typically accompanied by a detailed explanation on the methodology undertaken.
- Billing for large consumers is on a fixed monthly basis, and is limited to eight non-standard contracts, thereby limiting the transactional costs for retailers and direct billed large consumers.

11.3. **Principle A:** Prices are to signal the economic costs of service provision

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

Prices are economically efficient where the charges recovered from each consumer group falls within the subsidy-free range established by standalone cost (SAC) and avoidable cost (AC). SAC reflects the costs that a consumer would face to supply their energy needs from alternative energy sources. AC is the cash costs the network avoids if a consumer group were to disconnect from the network.

Horizon Networks' pricing approach is to allocate costs between consumer groups using cost-reflective allocators. This results in allocations that fall between SAC and AC on the basis that the cost allocators used represent the underlying network cost drivers.

The table below illustrates that Horizon Networks' average annual charges for each consumer group fall between SAC and AC and are therefore subsidy-free. The approach applied to estimating AC and SAC for each consumer group is described below and is based on guidance provided in the Authority's Practice Note.

Consumer group	Domestic and standard	Small	Medium	Large
Avoidable cost	$129.52	Immaterial	Immaterial	$135.80
Annual line charges	$707.52	$2,522	$9,867	$26,639
Average retail charge	$2,003	Not applicable	Not applicable	Not applicable
Stand alone cost	$8,936	$13,052	$51,618	$146,316

Table 13: *Horizon Network's subsidy free range (annualised)*

[1]*Average retail prices from MBIE, quarterly survey domestic energy prices, 15 Nov 2022. Assumes 6,130 kwh average consumption per annum.*

There is a risk that prices could exceed SAC for a small number of large customers located near the national grid connections. Horizon Networks uses non-standard negotiated contracts to avoid the risk of breaching SAC. New connections in remote regions may also have charges (including capital contributions) that exceed SAC.

Prices may also fall below AC for consumers with very low levels of annual consumption. This is partly due to the impact of the low fixed charge regulations, which limits the recovery of cost reflective charges from consumers with low annual consumption. With the phasing out of restrictions between 2022 and 2027, Horizon Networks considers that this will alleviate any potential cross-subsidy as fixed charges will exceed AC.

11.3.1. Standalone Cost

SAC reflects the costs that a consumer would face to supply their energy needs from alternative energy sources. This represents the cost of going 'off-grid' or bypassing the network. The Authority's Practice Note suggests that SAC should be estimated with reference to micro grid schemes under which a group of consumers share energy resources.

Prices above SAC cannot be sustained overtime as competing energy sources will encourage consumers to bypass the network. Consumers would be better off disconnecting from the electricity network and taking up the alternative energy solution where total electricity charges exceed SAC. This outcome is inefficient as charges for the remaining consumers would need to increase, which may potentially distort network usage.

Horizon Networks engaged independent advisors in 2021 to model a hypothetical standalone network for key consumer groups to estimate standalone costs. Standalone costs are estimated as the annualised present value cost of an off-grid energy solution sized to meet the consumer group's demand requirements. A typical off-grid micro-grid solution includes a combination of solar photovoltaics (solar PV), batteries, gas as a heating and cooking fuel, and diesel backup generation. Costs cover upfront equipment purchase and installation costs, replacement costs for assets that wear out, gas and diesel, and ongoing operating and maintenance costs.

This analysis showed that the cost of going off-grid is more expensive than grid supply. While the cost of solar is decreasing, the cost of back up supply (such as generators and batteries) required to deliver an equivalent quality of supply adds significant cost. Electricity supplied by the grid by comparison has higher economies of scale, given costs are spread across numerous consumers.

11.3.2. Avoidable Costs

The AC associated with a consumer group are the costs that would be avoided should the distribution business no longer serve that consumer group (while supplying all other remaining groups). If a consumer group were to be charged below its avoidable cost, it would be economically beneficial for the business to stop supplying that consumer group as revenue would not cover avoidable costs.

The avoidable costs for each consumer group are derived by estimating how future costs reduce if a consumer group is no longer supplied. Avoidable costs include short-term future cash costs, such as repairs and maintenance, billing and customer service costs.

Horizon Networks engaged an independent advisor in 2021 to calculate AC. Horizon Networks identified distribution costs in its asset management plant (AMP) that could be avoided if a consumer group were no longer served. Key costs that could be avoided were systems growth and connections expenditure and a limited amount of spend on service interruptions and emergencies. No Transpower charges were see as avoidable and avoided business support and system operation costs were immaterial given Horizon Networks has a relatively small network team and the requirement to continue to maintain the existing network assets and service remaining connections. For example, if the Domestic Low User Group was no longer served, the same business structures and resource would be required to serve the remaining consumers and operate the network.

Avoidable Costs of approximately $1.5m per annum were estimated for Standard and Domestic consumer groups. The AC for Large consumers was much lower at about $9k per annum. However, AC for small and medium commercial consumer groups (N2 – N5) were immaterial with no avoided capex and limited avoided opex. This reflects the limited growth in these consumer groups.

Horizon Networks have applied AC to setting the peak price component of our TOU pricing. Horizon Networks have estimated that the peak price should be about 4-5c per kWh higher than the shoulder charge to recover avoidable costs.

ii. Reflecting the impacts of network use on economic costs

Pricing structures are economically efficient where they assist to signal the economic costs of servicing different consumer profiles. A consumer group's use of network capacity, circuit length, and connection assets are the key drivers of economic costs.

11.3.3. Time of Use

Horizon Networks' previous pricing methodology used a per kWh consumption price that provides an incentive for consumers to reduce consumption overall. This is relatively poor at signalling economic costs. Horizon Networks has assessed and implemented new optional cost-reflective TOU pricing structures for domestic and low user customers that will improve price signals. The peak consumption charge under a TOU pricing methodology will be better at signalling economic costs than the existing methodology.

11.3.4. Non-Time of use pricing also signals impact of network use on cost to supply

However, Horizon Network's existing non-Time of Use pricing methodology continues to be available to consumers and this signals the impact of network use on cost to supply in a number of ways:

Avoidable costs

Our AC analysis revealed that only the Domestic, Standard, and Large consumer groups have avoidable costs. The AC features of these groups suggest they are appropriate for signalling economic costs.

The low levels of AC observed across these consumer groups also indicates that a relatively weak peak signal and a relative higher fixed charge proportion is appropriate for signalling economic and residual costs, respectively.

Connection capacity

Consumers are distinguished by capacity groupings explicitly in the 'general - capacity group' as well as more generally through our different sized pricing groups. These reflect different fuse or transformer sizes and circuit voltage capacity (eg Low Voltage (LV) and High voltage (HV)). These groupings recognise that costs to supply increase with network and connection capacity.

Connection density

Use of circuit length is factored into pricing through rural and urban pricing regions, which account for differences in costs and connection density. Rural customers pay more than urban customers for power reflecting the additional infrastructure that is required to service them. For example, more transformers are required to supply rural consumers than urban consumers, who are able to share supply from local transformers. Rural consumers use a higher proportion of HV circuits and lower proportion of LV circuits, given connections are often spread out more than in urban areas.

Demand and capacity charges

Demand (kW) and capacity (kVA) charges are applied to large consumer groups (N5, NMDU). This reflects the costs of providing both network and connection capacity.

Generation injection charges

Prices associated with DG injection loads have been incorporated into pricing to reflect their contribution to alleviating network congestion. Prices have initially been set to $0/kWh to collect generation data but may be used in the future to signal economic costs of serving generation loads.

Dedicated equipment

Large consumers with dedicated transformers and/or non-standard service requirements incur dedicated charges reflecting their unique requirements.

Streetlights

Separate streetlight charges seek to directly recover the cost of streetlight assets and maintenance.

Hot water control

Horizon Networks controls hot water heaters connected to the network. This hot water control is operated from May to September. Hot water cylinders are typically turned off in the morning and evening. This control reduces congestion on the network and the transmission grid at times of peak use and helps to reduce prices for customers.

11.3.5. Cost of Supply (COS) model

Horizon Network's Cost of Supply (COS) model (see Section 11.2) allocates the revenue requirement to load groups using the following allocators that reflect key network cost drivers:

- **Installation Control Points (ICP)** – reflecting connection related costs
- **Anytime Maximum Demand (AMD)** – reflecting usage of network capacity. The use of AMD seeks to fairly balance allocations to commercial and domestic consumers. Domestic consumers contribute much more to the network peak (which usually occurs in the early evening) but commercial users still contribute significantly to demand.
- **Depreciated Replacement Cost** of system fixed asset data – reflecting the cost of network assets
- **Load (kWh)** – reflecting general usage of the network.

These allocators ensure that prices reflect an economic allocation of the shared network costs which is consistent with the demand placed on the shared network in servicing each customer group. Work to ensure variable prices signal economic cost is ongoing, particularly as the TOU price differentials are reviewed and developed.

iii. Reflecting differences in network service provided to (or by) consumers

The key service that Horizon Networks provides is access to the network. Pricing distinguishes between different network service offerings that account for price and quality trade-offs, asset requirements, and consumption choices.

Specific examples of different network offerings in Horizon Networks' pricing methodology include:

Connection capacity

Pricing categories reflect standard connection capacity sizes (in kVA). Customers requiring a different level of capacity can be moved to other load groups that better reflect their required level of service and associated costs.

Use of dedicated equipment

Dedicated transformers and other equipment are provided to large consumers who have specific asset requirements. The cost of this service is recovered directly from these consumers.

Non-standard terms

Large industrial connections with atypical seasonal or daily load profiles are also offered non-standard terms to align Horizon Networks' pricing with their service requirements.

Distributed generation

Injection charges have been introduced to monitor the growing proportion of Horizon Networks' customer base with on-site generation (eg PV). This pricing option will be developed over time in response to changes in distribution generation connections (see discussion below for further detail).

Unmetered load

The service that streetlights and other unmetered loads receive reflects their use of network assets, captured in a separate pricing category.

iv. Encouraging efficient network alternatives

As discussed in Principle A (i), average charges are less than standalone costs for all consumer groups. Therefore, consumers are not incentivised to investment in inefficient off-grid energy solutions. However, Horizon Networks recognise that the current anytime based consumption prices, particularly those applied to residential and standard pricing groups, may encourage inefficient investments in network alternatives. At a residential consumer level, efficient network alternatives are encouraged through TOU pricing.

11.3.6. TOU Pricing

The TOU pricing structures are designed to be effective at signalling efficient investments in network alternatives such as solar PV, as consumers will be unable to fully avoid the cost of using the network at peak times when solar generation is typically lower. TOU pricing recognises that consumers with solar still contribute to the cost of serving peak demand.

11.3.7. Distributed Generation

Horizon Networks publishes a list of solar retailers online and offers customers the ability to apply for a DG connection. Consistent with Part 6 of the electricity industry participation code, eligible DG customers receive the benefit distribution costs that an efficient distributor would be able to avoid as a result of the electrical connection of that distributed generator.

Any new DG customers are offered the same opportunity to apply for and demonstrate they are providing a benefit to the network. This avoided cost of distribution benefit promotes the use of DG as an alternative to network investment, where it can be clearly demonstrated the costs of supply are reduced as a result.

11.4. **Principle 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

Residual costs are the remaining costs to recover from prices after deducting economic costs. Economic cost pricing governed by Principle A may under recover target revenue, especially where economic costs are low. Residual cost should be recovered through non-distortionary pricing mechanisms in accordance with Principle B.

Horizon Networks has recently estimated economic costs and residual costs when calculating AC for the new TOU pricing. Residual costs reflect about 95% of our annual target revenue requirement. This suggests that peak charges should send a relatively weak signal to consumers and that remaining costs should be recovered through pricing that least distorts consumer behaviour.

All consumers contribute to network residual cost mainly through the fixed component of prices. These cause minimal distortion because prices do not change with consumer usage behaviour. The high proportion of fixed charges (62% in 2023/24, or 71% excluding low-user plans) is consistent with the high level of residual costs on the network.

Horizon Networks utilises higher fixed charges (including capacity and demand charges) for large and commercial consumers that are less distortionary than consumption charges. The proportion of revenue from fixed charges compared to variable for commercial consumers reflects their contribution to demand during peak periods.

There is still likely to remain a proportion of our revenue recovered from off-peak and shoulder charges and other consumption charges. The off-peak and peak consumption charges are efficient in our view as they are times when consumers are less likely to change their usage decisions and they reflect economic costs. Shoulder and anytime consumption will remain to some degree but will reduce in importance as fixed charges increase. Table 13 below demonstrates fixed charges and the proportion of revenue derived from fixed charges across consumer groups.

Consumer Group	Daily fixed charge (as of 1 April 2023)	% revenue from fixed charges (year ended 31 March 2024)
Low User	$0.45 (ICP/day)	26%
Low User TOU	$0.45 (ICP/day)	26%
Standard User	$1.77 (ICP/day)	73.9%
Standard User TOU	$1.27 (ICP/day)	53%
N2U / N2R	$2.22/ $3.67 (ICP/day)	55%
N3U / N3R	$6.16/ $9.86(ICP/day)	55%
N4U / N4R	$13.39/ $15.45 (ICP/day)	57%
N5U / N5R	$0.116 / $0.130 (kVA/day)	60%
NMDU/NMDR	$0.0709 (kVA/day) $0.193 (kW/day)	70%
Large consumers	Based on individual contracts	100%
Total		62%

***Table 14:** Charges across consumer groups*

Horizon Networks' pricing strategy involves increasing the proportion of revenue from fixed charges, including as part of the low fixed charge regulation transition arrangements. If domestic low users had a similar proportion of fixed charge revenue to standard users, total revenue from fixed charges could be close to 80%. Horizon Networks expects this to be the case in the 2027/28 pricing year when the regulations are removed, and the low user fixed charge is fully phased out.

11.5. **Principle C:** Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:

i. Reflect the economic value of services

AC and SAC form the boundaries within which prices are set to ensure services reflect fair economic value.

Prices above SAC are unlikely to be sustainable in a market for alternative energy sources and may result in inefficient bypass of the existing infrastructure. Horizon Networks' prices are set below SAC. Bypassing the network is therefore discouraged in most cases. Horizon Networks sets prices above AC for each consumer group, therefore recovering the economic cost of supply for each consumer group.

Horizon Network's pricing reflects different network service offerings that are responsive to the needs of consumers (Section 11.3.5). Consumers can move load groups to meet their required level service. Dedicated equipment and non-standard terms are offered to large consumers, providing them a service that meets their specific requirements.

Horizon Networks is open to considering non-standard arrangements for large consumers that may have options for bypassing the network by connecting to the gas or electricity transmission network.

Non-standard contracts facilitate the negotiation of price and quality trade-offs providing a mechanism to address uneconomic bypass. Prices are determined individually for each major industrial consumer on the network. These prices reflect the specific assets associated with the supply of line function services and the quality of service requirements. Contracts of this nature are likely to reflect the economic value the consumer places on the service offering.

ii. Enable price/quality trade-offs

Non-standard arrangements that reflect different price-quality trade-offs can be negotiated for large industrial connections. Horizon Networks only does this by exception, to balance the need for non-standard pricing arrangements with the transaction costs faced by retailers and consumers.

Price/quality trade-offs are catered in pricing options by providing different service and asset options reflecting time of use, availability of supply, reliability and connection capacity:

- The new Opt-in TOU pricing allows consumers to select pricing options that allow them to make trade-offs on when they use electricity
- Demand and kVA bands allow consumers to self-select the capacity service they require, consistent with their willingness to pay
- Higher levels of security of supply can be agreed at the time of connection, and are usually funded separately through capital contributions
- Large general connections can choose between sharing a distribution transformer or having their own dedicated transformer. This reflects consumer preferences for security of supply.

Horizon Networks' pricing methodology recognises the installed capacity requirement of Network Maximum Demand (NMD) consumers. Consumers can select a combination of capacity and demand prices depending on their requirements. Combined with consumption charges, this ensures consumer demand is adequately reflected in the price paid and allows consumers to make trade-offs in service prices.

Prices charged to domestic and non-domestic consumers are not typically differentiated in the same way. General consumers are provided with a uniform quality of service with some differential reflected in urban/rural regions of the network.

11.6. **Principle D:** Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives

Horizon Networks' pricing is simple and is limited to fixed daily and variable consumption prices for the majority of consumers (excluding very large consumers). Load groupings are consistent with industry standards including a low user domestic group, a standard user group for single phase connections rated at no more than 60 amperes, and capacity groupings for other non-domestic consumers. These attributes help to minimise costs for both retailers and consumers.

Horizon Networks' pricing methodology and annual price changes are published on Horizon Networks' website. These disclosures provide relevant information that consumers and retailers need to understand how prices are set. Horizon Networks' pricing strategy signals changes in prices and the impact of price changes on different consumer groups.

Horizon Networks have reduced retailer transaction costs by developing pricing to reflect standard consumer profiles and connection characteristics, where possible. Prices apply to all consumers within each group.

No distinction is made between retailers. Horizon Networks applies the same charging structure to all retailers, excluding any non-standard contracts.

A separate contractual agreement is negotiated with non-standard consumers as they have unusual connection characteristics. Horizon Networks seeks to minimise transaction costs arising from its network charges, by limiting the complexity of charges and structures and the number of charging parameters within each charge.

The level of aggregate prices has been set within the constraints of the DPP Determination which is set and monitored by the Commerce Commission.

Appendix A. Information Disclosure Relevant Clauses

Clause 2.4.1

Every Electricity Distribution Business (EDB) must publicly disclose, before the start of each disclosure year, a Pricing Methodology which:

(1) Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;

(2) Describes any changes in prices and target revenues;

(3) Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and DG (if any); and

(4) Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.

Clause 2.4.2

Any change in the Pricing Methodology, or adoption of a different Pricing Methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different Pricing Methodology take effect.

Clause 2.4.3

Every disclosure under clause 2.4.1 above must:

(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;

(2) Demonstrate the extent to which the Pricing Methodology is consistent with the Pricing Principles and explain the reasons for any inconsistency between the Pricing Methodology and the Pricing Principles;

(3) State the target revenue expected to be collected for the disclosure year to which the Pricing Methodology applies;

(4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;

(5) State the consumer groups for whom prices have been set, and describe:

- **(a)** the rationale for grouping consumers in this way;
- **(b)** the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;

(6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;

(7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;

(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.

Clause 2.4.4

Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy:

(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;

(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;

(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.

Clause 2.4.5

Every disclosure under clause 2.4.1 above must:

(1) Describe the approach to setting prices for non-standard contracts, including:

- **(a)** the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts;
- **(b)** how the EDB determines whether to use a non-standard contract, including any criteria used;
- **(c)** any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the Pricing Principles;

(2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain:

- **(a)** the extent of the differences in the relevant terms between standard contracts and non-standard contracts;
- **(b)** any implications of this approach for determining prices for consumers subject to non-standard contracts;

(3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own DG, including any payments made by the EDB to the owner of any DG, and including the:

- **(a)** prices; and
- **(b)** value, structure and rationale for any payments to the owner of the DG.

Certification for Year-beginning Disclosure – Pricing Methodology

Clause 2.9.1 of section 2.9

We, ANTHONY DE FARIAS and LINDA ROBERTSON, being directors of HORIZON ENERGY DISTRIBUTION LIMITED certify that, having made all reasonable enquiry, to the best of our knowledge -

a) the following attached information of HORIZON ENERGY DISTRIBUTION LIMITED prepared for the purposes of clause 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) the prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

Dated: 27th day of January 2023

…………………………………………………..
ANTHONY DE FARIAS

…………………………………………………..
LINDA ROBERTSON

Pricing Methodology

For pricing introduced on 1 April 2023

31 March 2023