



Nelson Electricity Limited

Pricing Methodology Disclosure

For the period beginning 1 April 2023

The following information is disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012 under Part 4 of the Commerce Act 1986.

TABLE OF CONTENTS

- Director Certification2**
- 1. Introduction.....5**
- 2. Regulatory Requirements.....10**
- 3. Pricing Principles.....10**
- 4. Distribution Network Characteristics18**
- 5. Discussion on the Existing Pricing Regime.....18**
- 6. Pricing Change Discussion20**
- 7. Changes to the 1 April 2023 Pricing25**
- 8. Derivation of Line Prices.....29**
- 9. Future Changes45**
- 10. Non-Standard Contracts.....45**
- 11. Distributed Generation.....45**
- 12. Electricity Networks Association – Pricing Guidelines for Electricity Distributors.....48**
- 13. Pricing Schedule.....49**
- 14. Price / Quantity / Revenue Schedule.....51**
- 15. Future Pricing Roadmap Table – Progress Summary52**
- 16. Loss Factors to Apply for the Period 1 April 2023 – 31 March 202454**
- 17. Compliance with Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 200455**
- 18. Methodology for Passing-on Settlement Residual Rebates.....56**

Director Certification

In accordance with the Commerce Act
Electricity Distribution Information Disclosure Determination 2012


Nelson Electricity Limited - Pricing Methodology for the period beginning 1 April 2023

SCHEDULE 17 Certification of Year-beginning Disclosures

Clause 2.9.1

We, Philip J. Robinson and Oliver Kearney, being directors of Nelson Electricity Limited certify that, having made all reasonable inquiry, to the best of our knowledge:

- a) The following attached information of Nelson Electricity Limited prepared for the purposes of clauses 2.4.1, 2.6.1, 2.6.3, 2.6.6 and 2.7.2 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.

Signed 

Date 27 March 2023

Signed 

Date 27 March 2023

Glossary and Abbreviations

Advanced Meter	Also called a smart meter. Is a meter with the ability to measure energy use at various time intervals and with operational two-way remote communications capability. Installed at a Category 1 or 2 metering installation point ($\leq 500\text{Amps}$).	Low Fixed Charge Regulations (LFC Regulations)	Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Connection	A point of connection to an electricity distribution network as identified by an Installation Control Point (ICP) identifier.	Loss Factor	Loss factors are declared by distributors and used to reflect the normal difference between energy injected into a network and energy delivered from the network in the reconciliation process.
Controlled Meter	A meter that measures load where there is functionality to control the energy provided to permanently wired appliances (e.g. a hot water cylinder) that are connected to the meter.	Low Fixed Charge (LFC)	Low Fixed Charge.
Distributor	A company that owns or operates the power lines that transport electricity on local networks. Terms also used are 'distribution company', 'lines company' and 'network company'.	Lower South region	Stipulated in the LFC regulations as consumers supplied by the Arthur's Pass, Castle Hill, Papanui, and Hororata grid exit points, or any grid exit point that is located further south.
Electricity Industry Act 2010 (Act)	An Act that regulates the operation of the New Zealand electricity industry.	Meter Categories (1, 2, 3, 4, and 5)	Defined in the Schedule 10.1 of the Code. See Appendix 6.
Electricity Industry Participation Code (Code)	The Code sets out the duties and responsibilities that apply to industry participants and the Electricity Authority.	Meter register	An energy measurement device on a meter.
Electricity Information Exchange Protocol (EIEP)	EIEPs provide a set of standardised formats for business-to-business information exchanges.	Peak Load	Peak half hourly demand, measured in kW or kVA.
Electricity Networks Association (ENA)	Association of all 29 New Zealand electricity distributors.	Pricing Principles	The distribution pricing principles as published by the Electricity Commission in March 2010, adopted by the Electricity Authority.
Information Disclosure (ID)	Electricity Distribution Information Disclosure Determination 2012.	Registry	The registry is a national database that contains information on every point of connection on local and embedded networks to which a consumer or embedded generator is connected.
Input Methodology (IM)	Electricity Distribution Services Input Methodologies Determination 2012.	ToU Meter	Category 3, 4, or 5 metering installation capable of recording kWh and at least one of kVAh and kVAh on a half-hourly basis
Installation Control Point (ICP)	See Connection.	Transmission	Conveyance of electricity at high voltages through the Transmission network.
Kilowatt hour (kWh)	kilowatt hour is also known as a unit of electricity and is the basis of retail sales and reconciliation of electricity in the market.	Transmission network	New Zealand's national transmission network (national grid) owned by Transpower New Zealand Limited.
Legacy meter	A meter that measures cumulative energy consumption (kWh) and does not have remote communications capability. Installed at a Category 2 ICP or lower ($\leq 500\text{Amps}$).	Uncontrolled Meter	A meter that measures load where there is no load control functionality.
		Unaccounted for Energy (UFE)	The difference between reported energy injected into a network and the reported energy extracted from the network after it has been adjusted using Loss Factors.

The Electricity Authority also publishes a glossary of key industry terms on its website.

Introduction of New Pricing Structures

Nelson Electricity is introducing new Peak/Off-Peak pricing options for connections in consumer Groups 1 and 2.

Nelson Electricity is also introducing locational pricing for a small group of Load Group 2 consumers that are supplied by a rural line which incurs significant additional costs to maintain compared to the rest of the electricity network.

Full details are included in Section 6 - Pricing Change Discussion and Section 7 - Changes to the 1 April 2023 Pricing.

1. Introduction

Background

Nelson Electricity Limited is the Electricity Distribution Business that delivers electricity to electricity users on behalf of energy retailers. Nelson Electricity is responsible for managing and operating the electricity distribution network in the central Nelson city area.

By way of brief background, Nelson Electricity was formerly the Municipal Electricity Department of the Nelson City Council. The Electricity Industry Reform Act 1998 required that all electricity companies split into either the supply business (generating and/or retailing electricity) or the delivery business (operating the local electricity network). In 1999, Nelson Electricity sold its retail operation to focus on its electricity delivery business.

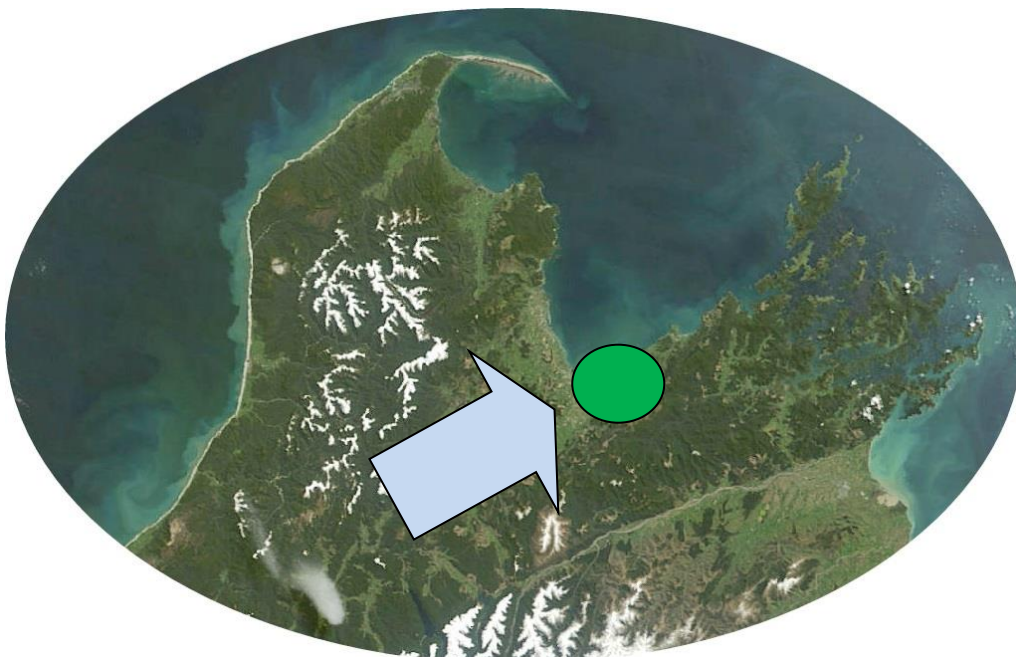


Figure 1 Nelson Electricity is in Nelson city at the top of the South Island.

Nelson Electricity is owned by Network Tasman and Marlborough Lines, each holding a 50% shareholding. The day-to-day operations are managed by a small team of executives, and all maintenance and capital work is outsourced to approved contractors by way of contestable tendering of works.

The Nelson Electricity network comprises approximately 9,300 connections in a concentrated area of 24 square kilometres in the central Nelson city area. The connections are largely CBD, industrial and dense urban. Nelson Electricity has a peak loading of 35MVA, during winter months and distributes 136GWh annually through the network.

Nelson Electricity derives its transmission services via Transpower's Stoke substation which is 7 kilometres from Nelson Electricity's only Zone Substation at Haven Road.

kWh Consumption

Nelson Electricity, from the 1950s up until 2008, had consistent kWh growth of approximately 1.0% - 1.5% per year.

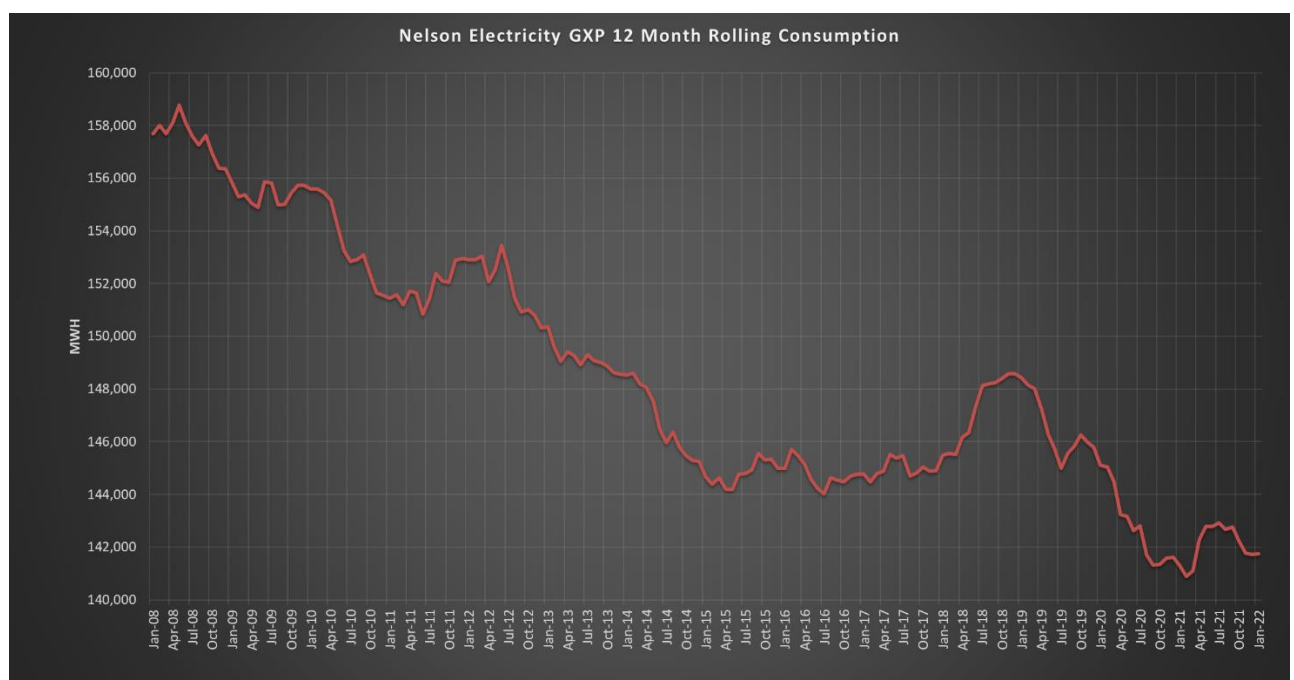
Between 2008 and 2015 kWh consumption then reduced at approximately 1.0% per year. The global financial crisis may have started the decline in consumption in 2008 but the decline continued due to the following changes at consumer level:

- Older appliances being replaced with more energy efficient options
- LED lighting replacing incandescent and compact fluorescent light bulbs
- Improvements in home insulation
- Greater energy conservation by electricity consumers
- Higher electricity prices
- Installation of solar PV.

Consumption flattened off between 2015 through 2017 and then increased in 2018 with a colder winter and hot summer, then returned to normal levels in 2019.

Covid-19 and some larger customer changes impacted the network in 2020 with consumption reducing 3% through the year. Consumption on a month-to-month basis since then (excluding the larger customer changes) has returned to previous year levels.

It is assessed that the short to medium term (1–5 years) outlook for Nelson Electricity is flat consumption. Electricity consumption is forecast to then begin increasing in the medium term (5-10 years) at 1% to 1.5% per year as electric vehicles become more cost effective, EV charging options become more prevalent on the network whether they be public or private and decarbonisation of other energy uses, eg boilers and industrial machinery becomes more prevalent. This increase in consumption will more than offset the increase of kWh being generated and used behind the meter through solar PV installations.



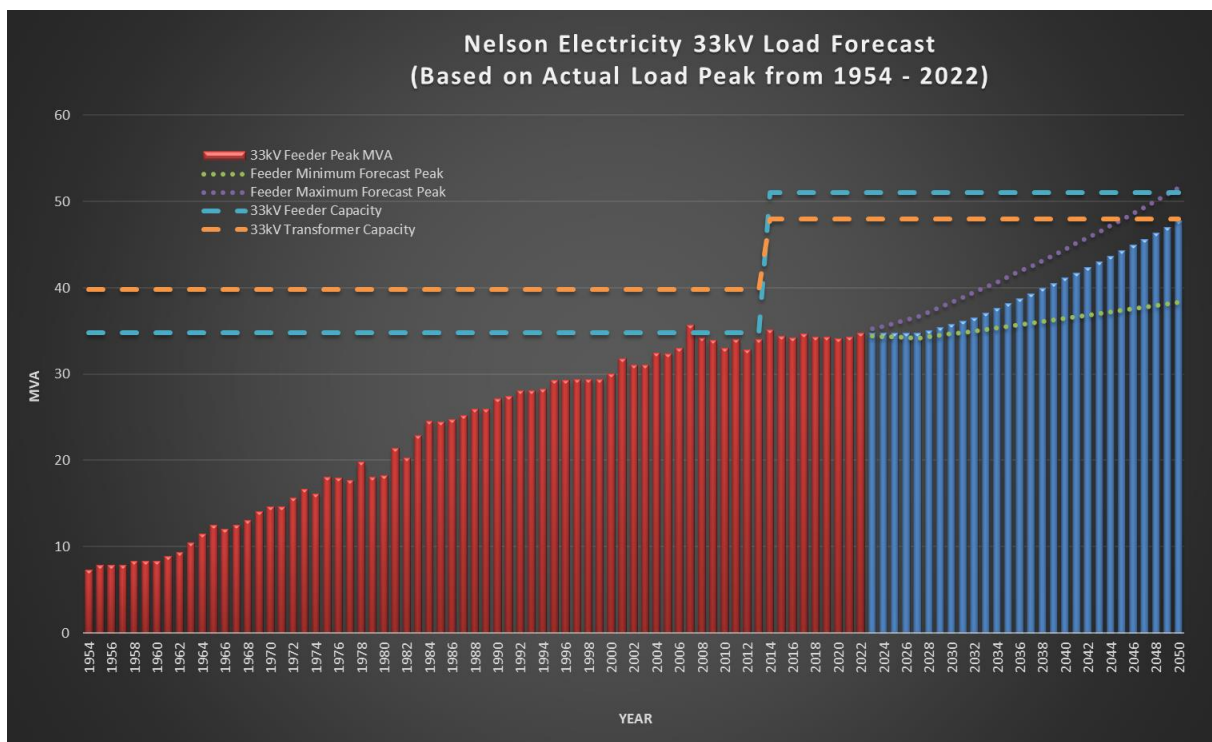
Peak Demand

Peak demand up until 2008 was also increasing at the same rate as kWh's at approximately 1.0% - 1.5% but since 2008 has flattened off but not decreased. This peak demand level has remained unchanged. The reason for peak demand growth has not tracked downward with consumption is due to the lower utilisation of load control at peak demand times. Load control is now being principally used for network and electrical industry emergency purposes and minimising transmission connection costs as there are currently no upper network constraints on the Nelson Electricity network to manage load for.

There is limited opportunity for new load/connections as there is limited undeveloped land available in the central Nelson city area. Many recent re-developments of land typically have resulted in no additional growth given any new building uses less electricity overall.

The following graph demonstrates how the peak demand has flattened since 2008.

With the information Nelson Electricity has on hand, it is assessed that the short to medium term (1-5 years) outlook for Nelson Electricity is no change to peak demand with 0% growth. Depending on the number and behaviour of EV charging and decarbonisation of other energy uses, eg; boilers and industrial machinery, peak demand could start to increase by 1% - 1.5% per year thereafter.

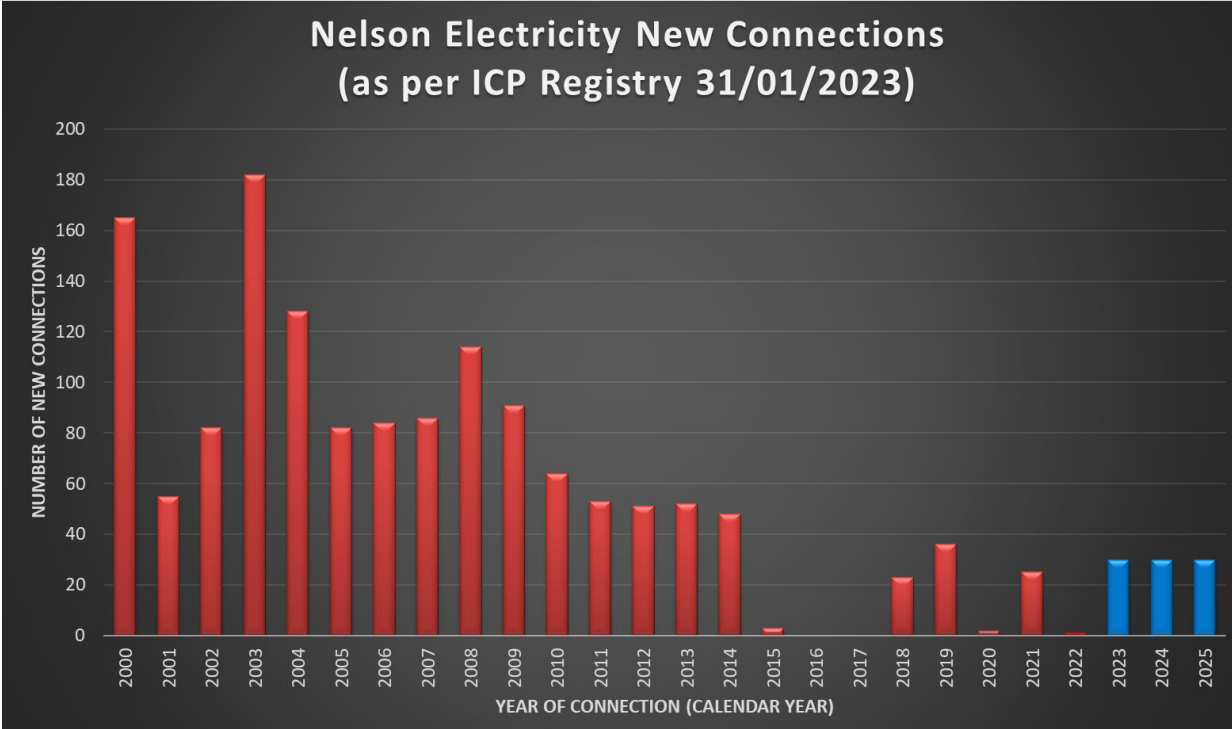


Connection Numbers

Connection number changes are calculated as being the difference between decommissioned and new connections. Between 2010 and 2015 Nelson Electricity has had on average 50 new ICPs a year. Most are typically new residential connections. Since 2015 decommissioned ICPs have offset most of the new ICPs which has meant that connection numbers have been flat for eight years. This is, however, not an indication of no growth as many decommissioned sites are making way for new future connections and the applications are now coming through with many starting to be realised.

Nelson City Council has also released their Intensification Action Plan in 2021 which looks at a guiding framework for Council actions to enable housing intensification in the area with a clear change to intensifying housing development in the central Nelson City area. Also Nelson City Council and Tasman District Council have released their Nelson Tasman Future Development Strategy 2022–2052. While the impacts of the plan and strategy will take time to deliver intensification results, there will clearly be a change in the number of connections, consumption and peak demand. This may begin to be material in the medium to long term (5 years plus).

Nelson Electricity has taken a conservative approach with forecasting 30 new connections in the 2023-2024 year.



Technology – Times are Changing.

On top of the flat consumption forecast, there is an increased uncertainty as to the effect certain technologies and industry evolution will have on the role the electricity network will play in the future. Nelson Electricity recognises its place as the key infrastructure that supports the Nelson region’s community and economy. Key areas of focus are as follows:

- Increasing numbers of solar PV installations
- Increasing number of retailers providing many different pricing options for consumers
- Introduction of battery storage
- Electric vehicles and vehicle chargers
- Internet of things.

The electricity consumer is starting to dictate the network’s future with their decisions on uptake and utilisation of these technologies and switching to different pricing options as electricity retailers adapt and modify their offerings. Nelson Electricity is, therefore, having to review its network pricing structure to ensure it is fit for the upcoming changes and ensure that the network is sustainable for the long term.

The reliance of consumers sourcing all electricity from the distribution network and transmission system is slowly reducing. With distributed generation already being installed and with home scale batteries beginning to be installed, this creates the opportunity for new electricity retail offerings to benefit these consumers including time of use pricing and peer to peer trading. Nelson Electricity is adapting to ensure the network can facilitate the changes and stay relevant for the community it serves.

Nelson Electricity has been actively working with the Electricity Network Association and neighbouring networks to develop and introduce a form of service-based/cost reflective pricing that meets the changing landscape. The new pricing options being introduced, Peak/Off-Peak pricing and locational pricing achieves the two key objectives:

- Ensure, as much as practicable, that all electricity consumers pay “their fair share” of the costs to provide the electrical infrastructure.
- The electricity consumer can make rational choices when investing in any new technologies.

Currently, consumers who can afford to invest in distributed generation and batteries and other things are not paying their fair share of network related costs. These costs are being subsidised by consumers that currently do not or cannot afford to invest in these technologies. The new pricing options begin to address this issue.

Decarbonisation of Energy

Nelson Electricity is mindful of the changes in consumption and demand in the near future. The Climate Change Response (Zero Carbon) Amendment Act 2019 provides a framework by which New Zealand can develop and implement clear and stable climate change policies that allows New Zealand to prepare for, and adapt to, the effects of climate change. The key target is the need to reduce net emissions of all greenhouse gases (except biogenic methane) to zero by 2050. The removal of carbon out of the many uses of energy is a key requirement to meet this target.

This decarbonisation of energy presents a unique set of challenges and opportunities. As more renewable energy sources are integrated into the electricity system, there is a need for new infrastructure and technologies to manage the variability of the sources and ensure a stable and reliable supply of electricity.

One of the main challenges for distribution networks is the integration of distributed energy resources, such as the rooftop solar panels. Solar can be unpredictable, and the output can fluctuate depending on weather conditions, which can cause voltage fluctuations and other technical issues in the distribution network.

The decarbonisation of energy also presents challenges for the network infrastructure. As more electric vehicles are introduced and decarbonisation of other sectors continues, there will be a need for upgrades to the distribution network to ensure that it can handle the increased demand for electricity.

At the same time, the decarbonisation of energy presents opportunities for distribution networks to become more flexible and efficient. The use of smart grid technologies, such as advanced metering infrastructure and demand response programs, can help to better manage the integration of distributed energy resources and balance the supply and demand of electricity.

Overall, the decarbonisation of energy presents both challenges and opportunities for distribution networks. As the electricity system transitions to a more sustainable and resilient future, there is a need for ongoing investment in infrastructure and innovation to ensure that distribution networks can manage the challenges and take advantage of the opportunities presented by this transition.

2. Regulatory Requirements

Nelson Electricity is a natural monopoly and is not directly exposed to the competitive forces that drive other markets to deliver improved efficiency and service. To this extent Nelson Electricity is classed as non-exempt from the control regime under the regulations for electricity network owners under the Commerce Act 1986. This means that Nelson Electricity must comply with the Electricity Distribution Services Default Price-Quality Path Determination 2020 (DPP) administered by the Commerce Commission. Nelson Electricity must also comply with the Electricity Distribution Information Disclosure Determination 2012 under Part 4 of the Commerce Act 1986 of which includes the disclosure of its Pricing Methodology. Recent changes also require the pricing methodology to demonstrate how the Nelson Electricity pricing is in line with the Electricity Authority Distribution Pricing Principles.

Nelson Electricity has taken all requirements into account in the preparation of this document.

2.1 Electricity Distribution Services Default Price-Quality Path Determination

Nelson Electricity must comply with the Electricity Distribution Services Default Price-Quality Path Determination 2020 (DPP). The Commerce Commission resets the Price-Quality Path every five years. The 2023-2024 year is the fourth of the current five-year path from 1 April 2020 – 31 March 2025. Nelson Electricity sets prices that when multiplied by forecasted quantities so that the net forecasted revenue is less than the Net Allowable Revenue.

Default Price Path Compliance Summary

Nelson Electricity, for the year ending 31 March 2023, will comply with the Default Price-Quality Path (DPP) revenue requirements. The Nelson Electricity Forecast Revenue which is based on 2023-2024 prices multiplied by forecasted 2023-2024 quantities will be less than the Forecast Allowable Revenue. This is demonstrated in the Nelson Electricity Default Price-Quality Path Annual Price Setting Compliance Statement.

2.2 Electricity Distribution Information Disclosure Determination

The key requirements in complying with the disclosure of pricing methodologies is outlined in 2.4.1 – 2.4.5 of the Electricity Distribution Information Disclosure Determination 2012. The requirements outline the framework to demonstrate to the “Interested Person” how Nelson Electricity allocates costs to different Load Groups and the basis on how prices are set.

3. Pricing Principles

3.1 Electricity Authority Distribution Pricing Principles

The Electricity Authority’s pricing principles are as follows:

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

- (i) **being subsidy free (equal to or greater than incremental costs, and less than or equal to standalone costs);**

Standalone Cost

Nelson Electricity is a dense urban network with no other reticulated energy options. The cost to either go off grid or bypass the network is too high for all Load Groups except for our one consumer in Load Group 4 of which bypass is possible due to proximity to our neighbouring network. Special pricing has been in place reflecting this for the Load Group 4 consumer for over 25 years.

The opportunity for consumers in Load Groups 1, 2 and 3 to go off grid is through use of distributed generation or changing to other sources of energy. The overall cost of these options (including upfront and ongoing costs) is materially higher than the cost of receiving supply from the Nelson Electricity network.

The number of solar panels required to go off grid has a cost and real estate implication. The quantity if complimented by batteries would have to be based on the peak consumption days, which is in wintertime. Most consumers will not have enough roof space to satisfy the kW requirements to be standalone. Consent issues with using wind and other natural resources is also an issue in a dense urban environment, so this is only a real possibility for a very small number of consumers on the fringes of the network. The only other alternative is changing or complementing distributed generation with batteries and another energy source, but there are limited options for competing fuels in Nelson city. Nelson has bottled LPG available, which could only satisfy the heating requirements. With the decarbonisation of energy use in New Zealand in the coming years, LPG will become less viable leaving its likely replacement hydrogen if and when this gas becomes viable and available.

Nelson Electricity will keep an eye on the standalone costs for each Load Group as the price of solar panels and home scale batteries reduces.

Avoidable Costs

Avoidable costs are those that can be avoided by not supplying a consumer or group of consumers. This can include the costs of billing and consumer service costs, connection costs specific to the consumer or consumer group and additional maintenance costs. Given Nelson Electricity is primarily a fixed cost business, the incremental effect on costs of a consumer or group of consumers disconnecting from the network is low. The effect on transmission costs is also low given the changes to the TPM. The current annual estimates of avoidable costs on a per consumer basis is:

Load Group 1 \$98 per consumer compared to average revenue of \$407.

Load Group 2 \$112 per consumer compared to average revenue of \$921.

Load Group 3 \$4,106 per consumer compared to average revenue of \$19,396.

- (ii) **reflecting the impacts of network use on economic costs;**

The network is currently not constrained from sub-transmission down to the 11kV network level. A study was recently undertaken to determine any potential constraints at the low voltage network level because of electric vehicle charging, battery storage and solar PV. The results showed there were no immediate constraints. **There are areas in the low voltage network that may be susceptible should the numbers of electric car chargers increase at a faster rate than forecast** (this could be an overall increase or specific areas or pockets).

Nelson Electricity's pricing needs to ensure the relevance of load control for this medium-term eventuality to eliminate the congestion or defer the need for network upgrades.

Network costs are predominantly stable with a relatively smooth capital and operational expenditure profile for the next 10 years (excluding the recent inflationary and service provider changes in costs). These network costs are mostly not location specific thus requiring multiple pricing areas.

There is one area on the network where a separate pricing area is being introduced in 2023 where the economic cost for Nelson Electricity is significantly greater than the revenue received. The Fringed Hill area supplying four commercial consumers has a 2 kilometre rural distribution line that is subject to additional costs compared to the rest of the network. Those being annual tree management, access corridor clearing, line maintenance and additional insurance. The true economic cost of providing line function services to the four consumers is greater than 400% - more than the current revenue received through standard pricing. Currently these consumers are on standard pricing. The new increase in prices will be fixed in nature given the additional costs are not load dependant.

The Nelson Electricity pricing regime has adapted over time with the gradual increase in revenue received through fixed charges. In 2015 fixed charges represented 52% of revenue and in 2023 fixed charges will represent 64% of revenue. The true economic cost recovery should be a significantly higher proportion of revenue from fixed charges than the current levels due to there being no significant constraints on the network. **The new pricing regime introduced April 2023 continues to reflect this transition to a higher proportion of fixed prices.**

The Nelson Electricity delivery prices will be based on there being no constraints at any level in the short term (1–5 years) with demand management becoming more relevant as load increases in some areas of the low voltage network as the number of electric vehicles increase in the medium term (5–10 years).

The current pricing reflects different network service offerings that account for price and quality trade-offs, asset usage requirements, and consumption preferences that have evolved over time. Key examples of consumer service preferences that are catered for in our pricing are also discussed:

- **Connection Capacity**
Nelson Electricity sees connection capacity as being the key pricing component. Every consumer can increase or decrease the connection capacity to suit their individual requirements. Current residential consumers have their connection capacity assessed at a standard residential fuse size of 15kVA to reduce the complexity of our pricing due to the inefficient impacts of the Low Fixed Charge regulations. **Business consumers can increase and decrease connection capacity to reflect their changing needs.** Nelson Electricity does not charge a consumer for any decrease but will charge actual costs for any increase in capacity. Increases are subject to network capacity availability.
- **Controllable Load**
Nelson Electricity pricing allows for controllable load options typically used for hot water and winter heating for Load Groups 1 and 2, and winter control period demand for Load Group 3 consumers. Pricing for controllable loads for Load Groups 1 and 2 is on a per kWh basis so consumers get the direct benefit of the cost differential between uncontrolled and controlled prices. Load Group 3 consumers have access to a load

control channel for the winter control period demand. They can opt for any of the business load to be controlled through that winter period. The benefit to the consumer is a lower Winter Demand, which reduces the charges that are applied the following year.

- **Power Factor Charge**
To encourage power factor management, a power factor charge is applied to Group 3 and 4 consumers who have a monthly peak demand below a power factor of 0.95. This signals to the consumer the need to manage power factor to optimise network capacity and quality of supply.
- **Non-Standard Arrangements**
Large business consumers who have differing needs can enter into a non-standard agreement with us. There are currently two consumers with Dedicated Connection Contracts that has allowed them to better manage their network and transmission costs.

Nelson Electricity is introducing a Time of Use Pricing(Peak/Off-Peak) for Load Groups 1 and 2 that will complement the existing capacity charges in April 2023. The new pricing regime provides consumers incentives to utilise electricity outside of peak demand times in advance of and to reduce the medium term forecasted low voltage network constraints.

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

Pricing is primarily centred around capacity (the maximum demand a consumer can draw from the network at any point in time). Nelson Electricity also uses load control to shift load out of peak times that can incur additional cost (transmission connection costs) or manage demand in an emergency or times of a constraint on the network. New Peak/Off-Peak pricing will also provide an incentive to shift consumption out of peak times. The price options available provide for some flexibility on the utilisation of both key options. Consumers can change options as and when they assess there is value.

(iii) encouraging efficient network alternatives.

Network pricing should be encouraging efficient investments in alternatives to transmission or distribution network supply. Current network alternatives include distributed generation, battery storage, interruptible demand, and demand management. **Nelson Electricity is introducing Time of Use (Peak/Off-Peak) pricing for Load Groups 1 and 2 and steadily increase the proportion of fixed prices which will assist in providing a stable long term pricing structure. This will provide consumers greater certainty when evaluating investing in efficient network alternatives.**

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

Nelson Electricity is introducing new pricing options in April 2023 that will better signal economic costs. The new pricing options are introduced with the knowledge that the network is currently not constrained in the short term (1–5 years). **The medium to longer term (5 years plus) will most likely see an increase in consumption and demand with the increase of electric vehicles as well as the decarbonisation of energy, which will see a transition from fossil fuels to electricity over the next 25-30 years. This will start to put pressure on the low voltage network resulting in the increasing need to utilise load control for network purposes.**

The current pricing regime has been moving more towards cost-reflective pricing with improved cost allocations between variable pricing options and the increasing of fixed charges to recover the shortfall. The new cost-reflective pricing structure being introduced will accelerate the transition to ensure consumers can respond/consider the true economic signals Nelson Electricity requires to maintain an efficient network.

If Nelson Electricity were to set prices according to the economic cost of the current environment of no network constraints, the proportion of revenue received from variable costs would reduce from 36% to approximately 10% - 20%. There would also be the lessening of the variable pricing differential between uncontrolled and controlled in the short term. Pricing in the medium to long term, due to upcoming low voltage network constraints, would result in the increase again of total revenue from variable charges and increased differential of controlled/uncontrolled or peak/off peak prices.

(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

As noted above, prices above stand-alone cost could not be sustained in a competitive market and may result in inefficient bypass of the existing infrastructure. As prices are significantly below the stand-alone costs, bypassing the network is discouraged suggesting that the prices reflect the economic value of services. However, Nelson Electricity is open to entering into non-standard arrangements for large connections that may be prone to bypass.

(ii) enable price/quality trade-offs

The Commerce Commission's Default Price-Quality Path regime limits incentives to offer price/quality trade-offs. It is not practical to offer mass market consumers a price/quality trade-off on an individual basis, given the nature of fault response and shared use of network assets. Nelson Electricity cannot offer slower response times or less redundancy to some mass market consumers and not others. Nelson Electricity has more ability to offer price/quality trade-offs to consumers that connect at higher voltages, but few incentive opportunities exist to do so especially if there is a want for lower quality. SAIDI/SAIFI is recorded on faults that are 11kV or higher. If Nelson Electricity entered into an agreement with a consumer connected to the HV network that offered lower lines charges and lower service quality, there is a risk of a higher SAIDI/SAIFI than we would otherwise incur – increasing our chances of breaching quality standards.

Nelson Electricity engages with larger consumers who are looking for a network service offering that differs from the current pricing. **Currently, there are two direct connection contracts and one non-standard arrangement. All three have differing requirements which have been met and are all mutually beneficial.**

Price/quality trade-offs for smaller consumers in Load Groups 1 and 2 are primarily around choosing the pricing option that is most appropriate to their situation. Currently there are several pricing options available to them.

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

The information provided in this Pricing Methodology demonstrates the transparent process used in setting of prices. This Methodology includes information around benefits or incentives of each currently available pricing option.

The development of prices focusses on achieving efficient outcomes for the long-term benefit of customers. In addition to this, retailer transaction costs are also taken into consideration.

A new Time of Use (Peak/Off-Peak) pricing structure is being introduced on 1 April 2023. The pricing is simple to apply for retailers and is easy for consumers to understand the benefits of shifting consumption. There will not be any significant price shocks for individual consumers as a result of this change.

Previous to the introduction of the Peak/Off-Peak prices, there have been no wholesale changes to pricing. NEL has however incrementally introduced a range of changes to simplify the application of our pricing.

- The simplification of Loss Codes and naming convention was introduced to better align with Load Groups and reduce risk of confusion. This made billing easier for retailers as the original codes were numeric and conflicted with some systems.
- Changed the start date by one month of when the Load Group 3 annual Winter Demand reset was to apply from. By changing the start date from September to October meant that the retailer could advise its customers within appropriate notice periods.
- Moves to standardisation expressed all prices in dollars which had previously been a combination of dollars and cents.
- Introduction of the NEL Pricing Guide to provide Electricity Retailers and electricity consumers assistance in the application of the charges for delivery of line function services on the Nelson Electricity Network.

Additional Commentary on Compliance with Electricity Authority Pricing Principles

Nelson Electricity has prepared this pricing methodology in accordance with, or as close as possible to, the Electricity Authority Pricing Principles.

Consumer behaviour, as a response to network pricing, is limited. The line prices represent approximately 30% of the total electricity invoice they receive from electricity retailers so unless a network can significantly amplify or exaggerate the pricing differential levels then the consumer behaviour will be based more on electricity retailer offerings. In addition to that, in the setting of controllable line charges, any incentives in these areas are often reduced further through the interface the customer has with their electricity retailer. Additional meter costs for measuring controllable loads are typically loaded onto the controllable price further reducing the pricing incentive for the line price option.

Prices are set attempting to minimise cross subsidisation and price discrimination between load groups. A key success has been in the mass market with the combining of business and residential tariffs, excluding those who qualify, and have opted to be on the low fixed charge option as per the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. This has reduced published pricing options for the mass market consumers also simplifying the pricing for electricity retailers to apply to their customers.

Upon completion of the new Zone Substation at Haven Road and installation of the new 33kV feeder in 2014, there have been changes in cost allocations given the reduced requirement for utilisation of ripple control for network related constraints or operational requirements. Ripple control is now principally used for minimising maximum network peak demand so reduces some transmission costs for consumers. This can be seen in the pricing schedules where **the transmission component is completely removed from the controllable pricing options.**

Nelson Electricity does not have any significant expenditure projects or material changes to its Asset Planning in the coming years that will materially affect line charges. Future load increases will see parts of the low voltage network start to be constrained and so there may be additional renewal/growth expenditure or the utilisation of load control or other load shifting options to mitigate against this.

Nelson Electricity currently offers a Time of Use line price option for larger commercial consumers. It is optional for all larger commercial consumers with a connected capacity up to 150kVA, above 150kVA is compulsory. This option is of benefit if those consumers can manage their load during peak winter demand times and incentivises the reduction of fused capacity. The consumer can choose what level of supply they require and will be charged accordingly. Noting that the winter demand charges are set in the winter and applied for the following 12 months from 1 October each year.

The Nelson Electricity’s pricing structure has remained stable for several years. The structure has provided stability and certainty. This does also minimise the transaction costs for retailers. The pricing is transparent, and all retailers have access to and are charged the same line charges for each different classification of consumer. Nelson Electricity has also considered retailer feedback into line charges. An example is the removal of a ripple control charge which was not part of the consumer’s line charge and was charged on a per retailer basis. The charge was rolled into the consumer’s line charges. This assisted retailers in reducing transaction costs.

Overarching the network pricing is that Nelson Electricity considers the requirements of its stakeholders. These are as follows:

Stakeholder	Interests
Electricity Customers	Delivery of a safe, reliable, efficient and sustainable supply of electricity at minimum cost. Surveys across the board say that most consumers do not want to pay more for a more reliable network.
Electricity Retailers	Delivery of a safe, reliable, efficient and sustainable supply of electricity at minimum cost. Diverse views on pricing options / standardisation and transparent pass through.
Government (Ministry of Innovation and Economic Development, Commerce Commission, Electricity Authority)	Legislate and control compliance of statutory requirements and economic efficiency.
Landowners	Landowners with Nelson Electricity assets on their property have interests in safety, easements and access requirements.
Property Developers	Property developers wish to ensure that connection policies and costs are fair and that network expansion plans are timely.

Stakeholder	Interests
Shareholders	Achievement of an adequate return on investment and good corporate citizenship.
Territorial Local Authorities	Territorial authorities have interests in minimising environmental impacts, development of underground power systems, local economic development and in the control of assets in road reserves.
Waka Kotahi	Waka Kotahi is interested in controlling assets in road reserves.
Transpower	Nelson Electricity relies on the Transpower grid to deliver electricity through to the Nelson Electricity network and Transpower relies on the Nelson Electricity network to deliver the electricity to end use customers.

Stakeholder interests have been identified and accommodated in the pricing of Nelson Electricity line charges through the following processes:

- The Nelson Electricity Board of Directors agrees to an annual Statement of Corporate Intent which details corporate strategy with respect to pricing.
 - To ensure the Company complies with all legislative requirements including health and safety legislation and all industry initiatives in respect of public safety and health and safety in the workplace;
 - To operate as a successful business in the distribution of electricity and other related activities;
 - To have regard among other things the desirability of ensuring the efficient use of electricity;
 - To ensure that all services and responses to maintenance and fault requirements are provided with an appropriate standard of customer service;
 - To maintain existing levels of reliability;
 - To have consideration of the consumer for price and quality;
 - To improve operational efficiency and productivity;
 - To adopt non-discriminatory pricing and network access policies for all users of the Nelson Electricity network;
 - To ensure that all resources, financial, physical, and human are utilised efficiently and economically;
 - To achieve a commercially acceptable return and to seek to maximise the longer-term value of shareholder's funds;
 - To provide for future development of the network through investigation and the acquisition of land and physical assets as is appropriate;
 - To be a good employer providing;
 - ✦ Remuneration consistent with performance,
 - ✦ A safe, satisfying and stimulating work environment,
 - ✦ Equal employment opportunities.
- Corporate organisational goals and objectives support the pricing methodology consistent with the corporate mission.

“Nelson Electricity’s principal mission is to own and operate the electricity network within the central Nelson area commensurate with appropriate standards of maintenance and reliability of supply whilst maximising shareholder value and providing a commercially acceptable return.”

- Surveys of residential, commercial and large user customers provide valuable feedback on pricing, security and reliability of supply which assists in network planning, and on the price-quality trade-off. The key outcome is that most consumers are happy with current quality and don't want to pay any more for improved quality. Consumers also are not willing to subsidise the line charges of those investing in new technologies.
- Government and territorial authority legislation provide a key input into the way pricing is set.

Any conflicting stakeholder interests are managed by systems that ensure that appropriate levels of separation, accountability and authority are in place. Pricing decisions are ultimately made at Board level with appropriate supporting evidence and recommendations from the General Manager.

4. Distribution Network Characteristics

Nelson Electricity is classed as an urban network and is supplying the following types of connections:

- Unmetered/Builders temporary – 47
- Residential – 7,785
- Small / Medium business – 1,373
- Larger Business (Time of Use) – 90

Nelson Electricity's pricing combines the residential and small/medium businesses (Load Group 2) for the purposes of pricing as the load characteristics are similar. The Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004, require Nelson Electricity to have a low fixed charge option for residential consumers using less than 8,000kWh per year (Load Group 1), which does result in some cross subsidisation between the two groups 1 and 2.

The Nelson Electricity network is centred on the business district of Nelson City and the Port area. It has a larger proportion of business connections compared to most other networks in New Zealand. As a result, the network peaks are typically experienced in the morning instead of early evenings. The Nelson Electricity network peaks are highest during the colder winter mornings when business load increases to start the day and residential is dropping off after the morning breakfasts and showers. The key driver is the high level of electrical heating load for both residential and business. The Nelson Electricity network is surrounded geographically by the Network Tasman network to the north and south. There is the ability for a very small number of consumers to bypass the Nelson Electricity network where the neighbouring electrical infrastructure is nearby. The cost to bypass in almost all situations is uneconomic given the cost to install network infrastructure versus the payback through any potential reduced line charges. Nelson Electricity would review any instance of potential uneconomic bypass and, if necessary, look at a non-standard pricing arrangement.

5. Discussion on the Existing Pricing Regime

The existing Nelson Electricity delivery pricing has been developed and modified to cater to the changing dynamics of the Nelson Electricity network. Network costs are allocated across all Load Groups and the pricing moves towards a more cost reflective regime where possible. Given the network is small geographically, there is no real benefit to have multiple pricing regions except for one small area on the network of which the economic cost for Nelson Electricity is greater than the revenue received.

Nelson Electricity as an Electricity Distribution Business sells capacity, the ability for electricity retailers to supply consumers with electricity. The consumer capacity limit is based on the fuses at the network connection point. The larger the fuses the greater the capacity available to the consumer at any time which potentially leads to higher capacity network infrastructure requirement to supply the network connection point.

5.1 Time of Use (Large Commercial)

The Time of Use pricing is for larger commercial connections. The pricing regime has not been materially changed since its introduction in the early 1990s. The delivery prices are split into five separate categories and priced accordingly so to ensure as much as possible that larger consumers are paying their fair share of the delivery costs and that there is minimal cross subsidisation. These prices are designed to be cost-reflective. The delivery prices in this group are clear and targeted which should incentivise the consumer to alter behaviour to minimise its delivery charges which will assist in optimising and maximising the utilisation of the network.

For Time of Use consumers, the pricing is centred on the connection capacity (size of fuses or transformer) and contribution to the network and transmission peak demand. The consumer can change both to reduce their overall delivery charges and assist in making the Nelson Electricity network more efficient. Given the pricing option has been in place for over 20 years, most of the efficiency gains have already been achieved in this group.

The weighting of the pricing categories has been modified over time to cater to the changing pricing signals required for the load group to match changing costs.

Analysis of the pricing regime suggests it is still relevant and delivers the required pricing signals for larger consumers to respond to.

5.2 Mass Market

All Commercial and Residential consumers (except consumers on the low fixed charge tariff option) have been grouped together to optimise the Nelson Electricity mass market pricing. There used to be a pricing differential between business and residential consumers, and over time, this differential was reduced and finally removed in 2009. It made it possible to link the two consumer groups together as it is also now extremely difficult to differentiate between the two groups where often there are businesses operating from home - bed and breakfasts as an example. The linking of the groups also reduced the number of published line prices and simplified the pricing to be disclosed making it easier for retailers to administer Nelson Electricity prices and consumers easier to understand.

Nelson Electricity also wanted to incentivise larger mass market consumers to optimise their electrical consumption and capacity. This was achieved by changing the fixed daily price which was a one size fits all to a price based on actual fuse size. This means that the larger mass market consumers pay a fixed delivery price based on their connected fuse size which is their ability to consume a higher electrical demand. They can also reduce their fuse size (free of charge) if they can change their load consumption behaviour. This delivery price option has proven successful with many consumers opting to have their fuse sizes reduced which then provides for reserved network capacity to be utilised elsewhere.

Larger consumers in this group can also opt to go on to the Time of Use tariff if there is a benefit for them to manage their load further. This option is, however, seldom taken up. There is more of a migration from Time of Use tariff to mass market and this is a result of the retail pricing options rather than the Nelson Electricity delivery prices.

Given that there are forecasted changes in consumption and peak demand in the medium to long term, it has been determined that a form of Time of Use (Peak/Off-Peak) pricing be introduced to ensure there is a pricing mechanism in place to incentivise shifting uncontrollable load into off peak times.

It was also determined that location pricing be introduced for a small number of consumers that are serviced by a 2km rural line. The economic cost to serve these consumers is significantly greater than actual revenue received so is being heavily subsidised by others on the network.

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

One complication with the capacity based fixed delivery price is the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 which means that a residential consumer using less than 8,000kWh must have access to a regulated fixed delivery price of which is increasing as the regulations are phased out. To comply with this regulation and to minimise delivery price options, Nelson Electricity has assessed all residential consumers fuse capacity at 15kVA. Currently a residential consumer with a larger fuse size is only paying the standard price of the typical 15kVA connection.

The compounding effect is that the average residential consumer on the Nelson Electricity network currently uses approximately 6,750 kWh per year compared to 7,400kWh per year in 2008. This is 9% lower than the deemed average consumer as determined under this regulation. This exposes Nelson Electricity to more cross subsidisation if more consumers switch to this price option. Of concern to Nelson Electricity is up to 70% of all residential consumers would benefit from being on the Low Fixed Charge option (Group 1). It is noted that in 2022 the number of consumers switching over has reduced to a point where they are offset by consumers switching back, so the issue has significantly lessened.

While the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 are being phased out, Nelson Electricity is exploring options to minimise the cross subsidisation as much as possible that this Regulation has created as it undermines the ability to adapt prices for changes in the network utilisation characteristics. Currently the consumers on Group 2 and Group 3 are subsidising the consumers on Group 1.

6. Pricing Change Discussion

6.1 Background

The old electricity supply model has changed from the one connection to the transmission grid and the network supplying thousands of electricity users, to many sources of electricity supply with distributed generation and batteries supplying the many electricity users. This can ultimately create an “uber type” market where electricity users may be able to sell/trade excess electricity to their neighbours. The important enabler is a robust electricity network that can cater to the changing consumer requirements.

Nelson Electricity has been indicating that current network pricing needs to be reviewed given the rapid changes in the emerging technology space. The key technologies are:

- **Distributed Generation including Solar PV** – Providing electricity users a method of generating their own electricity.
- **Batteries** – Providing electricity users the ability to manage their electricity use through storage.
- **Electric Vehicles** – A new electrical load that can provide a lower cost means of transport.
- **Advanced Metering** – Provides electricity users the opportunity to make informed choices about their electricity use. The one size fits all approach with one meter reading every two months will disappear.
- **The Internet of Things (IOT)** - The network of physical devices, buildings and other items—embedded with electronics, software, sensors, and network connectivity that enables these objects to collect and exchange data.

These technologies, particularly when used together, provide electricity users the ability to manage their electricity to their own personal advantage. Depending on their needs and pricing signals they react to, may or may not assist the network. There will also be a range of customer reliance on the electricity network from most that are 100% reliant to those who will use the network only as a backup/support option. Any new pricing structure needs to cater to both and all in between.

The current regulatory environment around pricing limits Nelson Electricity's ability to introduce an effective pricing structure that is fair to all consumers, this is however has changed with the phasing out of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. Consumers who can afford to invest in distributed generation and batteries among other things are not paying their fair share of network related costs. These costs are being subsidised by consumers that currently do not or cannot afford to invest in these technologies. Any new pricing must ensure this pricing imbalance is removed as much as practically possible.

The electricity consumer will ultimately decide on the future viability and shape of the electricity network as they start to take advantage of these changes. It is clear to Nelson Electricity that a new pricing methodology needs to be implemented that will stand the test of time taking into consideration these upcoming influences/changes. It will show a level of predictability/consistency to ensure that electricity users can make informed choices when deciding on investing money into any of these technologies and how and when they utilise electricity from the network.

Nelson Electricity is mindful of the magnitude of the change and as such has invested itself into the review of technologies, consumer behaviour and pricing options. This has been achieved principally through working with both shareholders and the ENA Distribution Pricing Working Group (DPWG) as well as keeping up to date with the advances being made with the technologies.

It is critical that any new pricing needs to align with other distribution networks in New Zealand as much as possible. The DPWG is published a paper on future pricing which provides some assistance in this regard. A new cost-reflective pricing structure is being introduced on 1 April 2023.

6.2 Issues for Pricing Changes

Nelson Electricity is cognisant of the opportunity that advanced meters are presenting to most electricity consumers in the Nelson area. There is now increased consumption information available for consumers and provide retailers with more opportunity to introduce new price offerings and increasing pricing variations.

With the medium term (5–10 years) forecast of some low voltage load constraints, pricing will need to factor in a greater requirement for network load management. The value of this load management requirement to eliminate constraints or defer network investments is factored in this cost reflective pricing from 2023. This will provide electricity consumers with some price certainty when making long term investment decisions with any of the technologies mentioned in Section 8.0.

Nelson Electricity has analysed several pricing structures for implementation.

The development of a form of **cost-reflective pricing** to ensure a fair economic cost allocation will keep a fixed daily price based on fuse size/capacity but shift away from simple kWh charges to a methodology that could focus on consumption/demand at peak times. The concept is to provide the electricity consumer the incentive to utilise electricity outside of peak demand times no matter whether they have access to new technology or not.

Introducing targeted time of use option while new to many will cater to the electricity consumer being able to make rational choices when investing in new technologies by providing incentives if they chose to shift electrical load out of network peak times. It must be recognised that networks sell capacity or demand not kWhs. kWhs have been used as a proxy for demand up until now as this was the only method of measurement available with the electricity meter being read every one or two months. Advanced metering is the enabler that will provide the opportunity to make the change to include targeted time of use.

There will be the complication of an increase in the number of line price options available to consumers, but this will be unavoidable. Consumers and retailers will need to be educated on the changes so they can understand the opportunities and implications.

Nelson Electricity needs to minimise any potential additional cross subsidisation or price discrimination that may occur with the two types of metering (advanced metering and non-half hour) with the consumer potentially being able to opt for one or other. Nelson Electricity has decided to make any pricing change mandatory for connections with advanced metering.

Ripple control needs is a serious consideration with the new pricing. This has been the most effective tool for networks in managing electrical load since its introduction. It is critical that this is retained. The new pricing will still include the existing load-controlled pricing options.

A pricing structure and transition plan needs to be in alignment as much as possible as other Networks.

Electricity Retailers have been consulted on proposed changes and their responses factored into the final pricing change decisions. Also, the network pricing structure is relatively simple that can complement retailer pricing as far as practical and not conflict.

The network pricing structure should be relatively simple to apply and understandable for electricity consumers.

Pricing still incentivises continued use of load control. Load control system is a key network tool and the benefit of this needs to be preserved.

New prices factor in regulatory imposed pricing factors eg; Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.

Seasonal price shock was an issue. In a true cost reflective pricing structure, most of the network cost recovery should occur during the winter months. This, however, is not necessarily the most appropriate for consumers and a methodology should balance out the desire for consumers to have less variance on a season-to-season basis versus being truly cost reflective.

Individual customer price shock. Any pricing change has winners and losers. Introducing a new pricing structure is necessary to ensure there is a structure that attempts to ensure all electricity consumers pay their fair share of network related costs. This will also ensure that the network will remain viable for the Nelson City community.

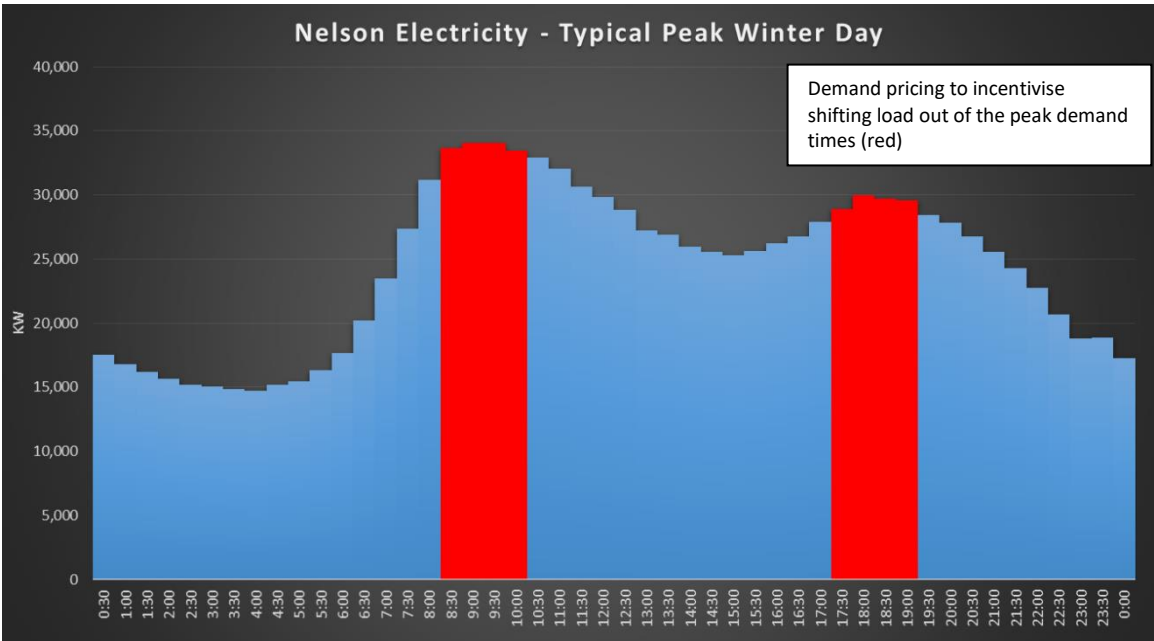
6.3 Pricing Options Considered

Nelson Electricity has reviewed several pricing options. The following are two alternatives which were finally considered. The objective was to provide a pricing structure that will ensure that network costs are applied and recovered in a fair manner for all electricity consumers.

Option 1 - Capacity and Demand

Capacity Charge - based on fuse size or capacity limiting option using advanced meter. Currently all Nelson Electricity consumers have a capacity charge based on the size of the fuses at their Network Connection Point.

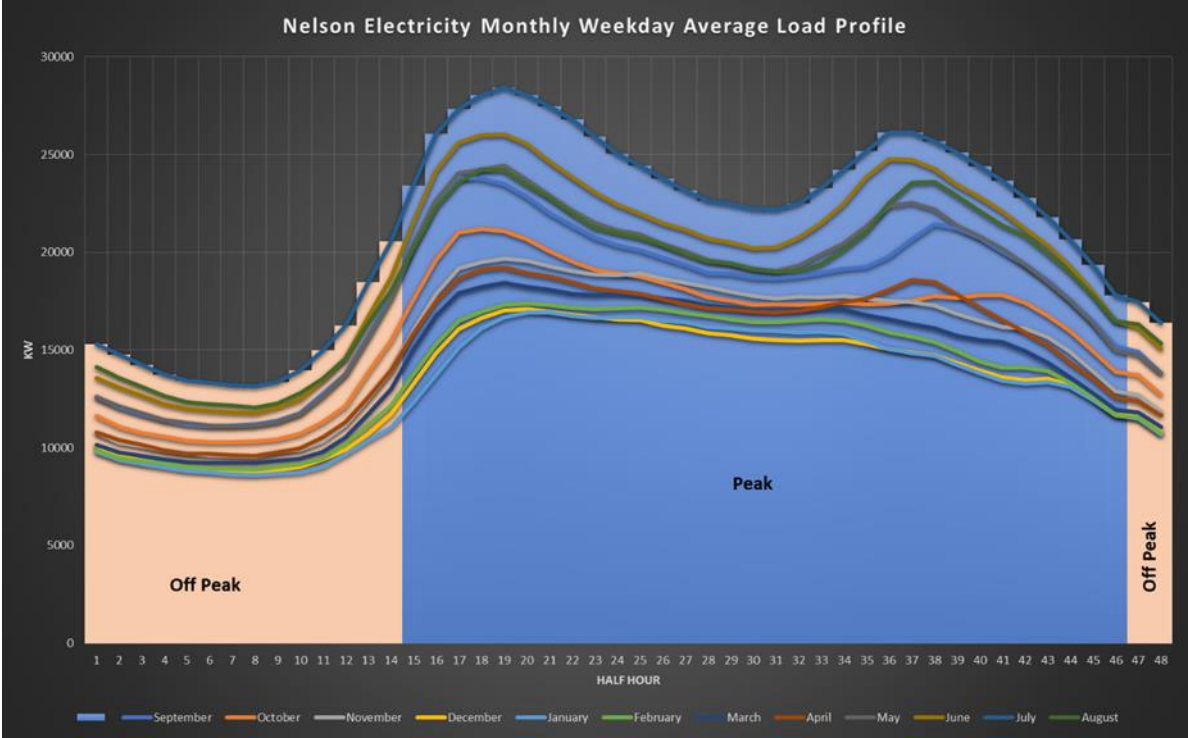
Demand Charge - Introducing a control period **demand charge** during peak demand timeframes. The timeframe to be set based on the likely transmission peak pricing times (typically match Nelson network peak demand times). Peak demand excludes any hot water load control.



Option 2 - Capacity and Time of Use

Capacity Charge - based on fuse size or capacity limiting option using advanced meter. Currently all Nelson Electricity consumers have a capacity charge based on the size of the fuses at their Network Connection Point.

Time of Use – Introduce time of use pricing. Have two pricing bands with Peak/Off-Peak pricing, a daytime price with a low night-time price. This will provide consumers with the opportunity to reduce costs by shifting consumption to different times of the day.



6.4 Future Pricing Summary

The new cost-reflective pricing structure being introduced on 1 April 2023 is Option 2. This timeframe is in alignment with many other electricity networks. It was determined this pricing approach was simpler to implement, understand and be applied by retailers.

6.5 Customer Consideration

Overview

Nelson Electricity communicates with customers mainly by way of radio advertising, newsprint and website covering issues relevant at the time including pricing.

Nelson Electricity also surveys customers periodically to get a better understanding of their wants and needs and where Nelson Electricity can improve.

Informal feedback, because of the price and quality information from the mass market, indicates customers have lost touch with the role an Electricity Distribution Business plays in the electrical industry since the separation of Line and Energy companies in 1999. The mass market customer only considers the total electricity bill value without separating out delivery prices. The perception to

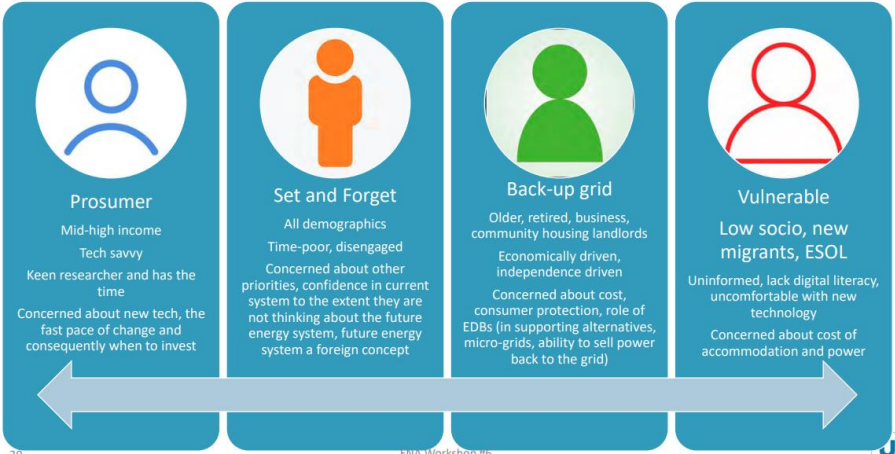
them is that electricity prices are always increasing and have little regard to the fact that delivery prices have remained the same or at similar levels while retail electricity prices have increased (up until recent times). Consequently, it is difficult in some instances to discuss and demonstrate price versus quality trade-offs.

Consistent outcomes from surveys of both large and small consumers suggest they are happy with current reliability and not willing to pay more for an improved reliability. Also, they do not want to pay less for a less reliable supply.

Customer Consideration into Future Pricing is a Difficult Area

The Electricity Network Association undertake Consumer Workshops. In this they have determined there are broadly four types of consumers all with differing perspectives, wants and needs.

Four Personas described



Pricing that can cater to all groups will be difficult. Cost reflective pricing, which least distorts pricing signals, is the only way to move forward.

7. Changes to the 1 April 2023 Pricing

7.1 Summary

The Nelson Electricity delivery prices will be changing 1 April 2023.

The Nelson Electricity Delivery Price Schedule that applies from 1 April 2023 is included in Section 13.

Nelson Electricity is introducing new Peak/Off-Peak pricing options for ICPs in consumer Groups 1 and 2 (15kVA -150kVA). These new pricing options will be 1P and 2P.

The peak period is proposed to cover 7.00 am to 11.00 pm weekdays, with the off-peak period covering all other times including weekends (no differentiation for public holidays).

Nelson Electricity will transfer all Load Group 1 and Load Group 2 consumers with communicating AMI meters from the existing pricing options 1 and 2 to the new Peak/Off-Peak pricing options 1P or 2P on 1 April 2023.

Nelson Electricity is also introducing locational pricing for a small group of Load Group 2 consumers that are supplied by a rural line which incurs significant additional costs to maintain compared to the rest of the electricity network. The fixed line charges will be increased over a 5 – 10 year period to recover the additional costs to maintain the rural line. The new pricing option is 2R.

The only other change is the increase of the Low Fixed Charge Tariff Option for Residential Consumers as per the changes in the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 from 1 April 2023. The increase is from 2 cents/kVA/day of connected capacity to 3 cents/kVA/day of connected capacity (all residential consumers have an assumed connected capacity of 15kVA). This increases the fixed charge from 30 cents/day up to 45 cents/day. This will apply to Pricing Groups 1 and 1P.

7.2 New Peak/Off-Peak Price Plans

Nelson Electricity is introducing two new uncontrolled pricing options: Peak/Off-Peak for each of the new 1P and 2P price categories.

These two price options must be used in combination and are proposed to have the following characteristics:

- Peak - Weekdays 07:00 to 23:00
- Off-peak – All periods outside of Weekdays 07:00 to 23:00
- No differentiation for public holidays.

The illustrations below displays when the two tariff options will apply.

		Weekday - period starting																								
		0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	
Peak																										
Off-peak																										
		Weekend - period starting																								
		0:00	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	
Peak																										
Off-peak																										

Peak/Off Peak Pricing Timeframes

All consumers on the 1-24HR or 2-24HR - Anytime (uncontrolled) tariff identified on the Registry as having a communicating AMI meter will, on 1 April 2023, be moved to the Peak/Off-Peak tariff 1P-PEAK and 1P-OFFP or 2P-PEAK and 2P-OFFP tariffs. Consumers with legacy or non-communicating AMI meters will remain on the existing Anytime tariff (eg; 1-24HR or 2-24HR).

The criteria for being moved to the Peak/Off-Peak tariff will be based on each ICP’s AMI Comm attribute in the Registry as at 31 March 2023.

Existing Price Categories “1” and “2” that include pricing codes with the suffix “24HR” will be closed to new consumers from 1 April 2023. The default uncontrolled tariffs will become the Peak/Off-Peak tariffs in pricing groups “1P” and “2P”. The standard controlled water heating price code “WATER” and “NIGHT” remains unchanged.

ICPs with communicating AMI meters at 31 March 2023

ICPs with communicating AMI meters at 31 March 2023 will have the option of:

- Peak/Off-Peak Pricing Options - the new Peak/Off-peak pricing option for uncontrolled energy consumption, and if applicable
- WATER - controlled load tariff (typically hot water heating)
- NIGHT –night-only tariff for controlled load 2300-0700
- DG – Distributed Generation

Based on current Registry information, it is expected that 87% of consumers which are those who have half hour metering installed will be transferred on to the new Peak/Off-Peak pricing options.

All new consumers will also be on this pricing option.

In all circumstances, the price codes used in the EIEP1 reports are prefixed based on the ICP Category code, eg; “1P” or “2P”.

ICPs that do not have a communicating AMI meter

Existing ICPs that don’t have a communicating AMI meter will remain on the pricing categories 1 and 2 and continue to be reported with our existing price codes, and if applicable:

- 24HR (Anytime) for uncontrolled consumption.
- WATER - controlled load tariff (typically hot water heating)
- NIGHT –night-only tariff for controlled load 2300-0700
- DG – Distributed Generation

Based on current Registry information, it is expected that 13% of consumers which are those that do not have half hour metering will remain on their existing pricing option.

In all circumstances, the price codes used in the EIEP1 reports are prefixed based on the ICP Category code, eg; “1” or “2”.

Operational matters

The introduction of a Peak/Off-Peak pricing options for Load Group 1 and 2 consumers requires half hour data to be time-sliced and consolidated into the relevant peak and off-peak periods for network reporting.

Nelson Electricity recognises AMI meters are imperfect and retailers may not have the systems in place by 1 April 2023 so may occasionally be unable to procure the data necessary to provide actual Peak/Off-Peak consumption for an ICP. To account for this, Nelson Electricity is introducing a “Default” pricing code for each price category “1P-DEF” and “2P-DEF” that retailers can use in circumstances where they are unable to provide actual Peak/Off-Peak consumption.

Where a retailer has reported against the default tariff in the initial EIEP1 reporting cycle, Nelson Electricity prefers the retailer to report Peak/Off-Peak consumption for the ICP if the data is available for the R3 replacement EIEP1 reporting cycle.

There is no difference in prices between the Group 1 pricing and the new Group 1P (Peak/Off-Peak) pricing when using the “Default” uncontrolled rate. There is also no difference in prices between the Group 2 pricing and the new Group 2P (Peak/Off-Peak) pricing when using the “Default” uncontrolled rate.

NEL, in recognising that retailers may take time to change their billing systems to accommodate this pricing change, will use the Default Rate instead of the Peak/Off-Peak rate in the interim including the revision 3 billing cycle.

NEL expects that as retailers change their billing systems the kWh volumes being reported on the default “DEF” price codes will reduce throughout the year.

Defining the tariff profile

The driver of how we designed this tariff was informed by the timing and duration of our network peaks. This is because we want to encourage consumers to shift discretionary demand, such as EV charging, dishwashers, washing machines, etc away from the peak periods and into the off-peak periods.

The average network load profile exhibits morning and evening peaks with a trough in demand during the middle of the day and a large trough in load overnight. Generally, the Nelson Electricity load follows this profile.

When designing this tariff, we have focused what the network load will be on the worst days of the year (not the average) when areas of the network could be reaching its capacity limits and load-shifting capabilities are fully utilised. This is because it is load at these times that trigger network investment. How consumers use the network on these days has a significant effect on the timing of these network investments.

Customer impact assessment

The design and introduction of Peak/Off-Peak pricing is to have minimal impact on consumers in the first year. The aim is to bed down the new tariff structure and, as the requirements for greater consumption to shift out of peak time arises, is to then have the pricing differential between Peak and Off-Peak increased.

Our analysis does show that the average mass market consumer will benefit from the Peak/Off-Peak pricing change. The more they can shift load from Peak times to Off-Peak times then they will benefit more. Note: the ICPs with the maximum savings are those with the highest uncontrolled kWh consumption. The savings compare Pricing Categories “1” with “1P” and “2” with “2P”.

Residential Consumer Impacts	Average Annual Revenue	Maximum ICP Saving	Average ICP Saving
Load Group 1P			
Mass Market Profile Comparing 1 and 1P	\$417.87	\$8.30	\$1.07
Shift 8% from Peak to Off-Peak	\$413.58	\$41.50	\$5.36
Load Group 2P			
Mass Market Profile Comparing 2 and 2 P	\$580.94	\$37.52	\$4.90
Shift 8% from Peak to Off-Peak	\$576.42	\$72.15	\$9.42
Mass Market 1P and 2P Combined			
Mass Market Profile	\$490.32	\$37.52	\$2.77
Shift 8% from Peak to Off-Peak	\$485.93	\$72.15	\$7.16

7.3 Locational Pricing

Nelson Electricity has undertaken a study on its network to determine whether there are any areas where locational pricing should be considered. There has been one area identified where the economic cost for Nelson Electricity is significantly greater than the line charge revenue received. The supply to these consumers is being subsidised by the rest of the Nelson Electricity consumer base.

The Fringed Hill area supplying 4 commercial consumers on Load Group 2 has a 2km overhead rural distribution line that is subject to significant additional costs due to location compared to the rest of the network, those being, annual tree management, access corridor clearing, line maintenance and additional insurance. The true economic cost of providing line function services to these consumers is greater than 400% more than the current revenue received through standard pricing. Currently these consumers are on standard Load Group 2 pricing.

Any increase in prices will be fixed in nature given the additional costs are not load dependant. It is proposed that the fixed capacity charge be increased annually over a 5 to 10-year period to a point where consumers on the top of Fringed Hill are contributing to the full cost service their connections.

A new remote tariff group option will be introduced "2R". The fixed charge 2R-Fixed is being introduced with corresponding "2R-24hr" uncontrolled kWh option. The kWh rates will be the same as the standard Group 2 pricing.

Customer Impact Assessment

The average business consumer shifting from Pricing Category "2" to "2R" will see average annual line charges increase from \$940 up to \$1,130. This represents an increase of 20% overall. It is expected that the capacity charge will continue to be increased annually at a similar rate until the consumers are paying the true economic cost of their connection.

8. Derivation of Line Prices

The Derivation of Line Prices are described in the following sections.

- Customer Groups
- Customer Group Statistics
- Allocation and Recovery of Network and Transmission Charges
- Cost Recovery per Load Group
- Fixed v's Variable Charges

8.1 Consumer Groups or Load Groups

Nelson Electricity has split its consumers into five distinct consumer groups/load groups to assist in the fair allocation of costs and setting line price levels. The Groups are based on the type of connection which considers typical load patterns, fuse size and annual kWh consumption. The number of groups is set at five as a balance between minimising complexity and ensuring costs are appropriately apportioned between consumers. The groupings are relatively in line with other electricity networks in New Zealand.

- Load Group 0 – (Pricing Categories 0-UM, 0-BT and 0-SL)
Unmetered Load or Metered Builders Temporaries. This group is for the smaller/lower fused connections (under 15kVA) either metered or unmetered that do not fall into the other groups as listed below. Most of the connections are either metered builder's temporary supplies or small unmetered supplies to telephone boxes and streetlights. This group has smaller connections with differing load characteristics, so a fair allocation of costs is difficult to demonstrate but the overall revenue of this group is only 0.05% of total revenue (excluding local council streetlights), so they are grouped together.
- Load Group 1 – (Pricing Categories 1 and 1P)
Residential consumers Low Fixed Charge Options – Connections that are a residential home that exhibit a typical residential load profile using less than 8,000kWh per year. A residential connection is where electricity is supplied to a premise that is used or intended for occupation by a person principally as a place of residence. It does not include a premise that constitutes any part of a premise described in section 5(c) to (k) of the Residential Tenancies Act 1986 (which refers to places such as jails, hospitals, hostels, hotels, and other places providing temporary accommodation). The connection size is set at 15kVA.

The Nelson Electricity Limited (NEL) Network Code allows for single phase 60amp, two phase 40 amp or three phase 30amp supplies to be classed as a residential connection. A residential type load profile not on the Low Fixed Charge option is typically categorised as Load Group 2.

- Load Group 2 – (Pricing Categories 2, 2P and 2R)
Residential and Small Business consumers – Connections that are 15kVA up to 150kVA. Residential consumers not on Low User Option are also in this group. The residential and commercial consumers are grouped together as much as Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 allow. Existing residential consumers are all assessed as 15kVA. Electricity network key costs are driven based on capacity (the ability for a consumer to take as much electricity up to the fused capacity at the Nelson Electricity network connection point). While there is a difference in load profiles from a typical business and a domestic connection it is proving more difficult as time goes on to differentiate between the two as many connections are a mixture of the two. To avoid complications in grouping allocations and number of tariffs, Load Group 2 joins the two consumer types together. By doing this it has removed any price discrimination that existed when commercial and residential were grouped separately.
- Load Group 3 (Pricing Categories T-03 – T-13 and T-15)
Large Commercial consumers with supply up to 2400kVA - This group is for any connection with a supply up to 2400kVA that wants to be on a Time of Use tariff. Time of Use tariffs were first offered to consumers in the early 1990s and the early rationale for the consumer being in this Group was if they used greater than 50,000kWh per year. The kWh requirement has since been removed and a mandatory requirement of connections with a capacity of greater than 150kVA to be Time of Use introduced. Those below that limit can opt to be on Load Group 2 or Load Group 3. This group is ideal for consumers that can manage their peak demand to minimise line charges as the line charge regime for this group more accurately reflects the consumer's fair allocation of costs.
- Load Group 4 – (Pricing Category T-14)
This group is for the largest commercial consumers on the network. Consumers with capacity supplied of greater than 3000kVA with supply from dedicated 11kV/400V substations.

8.2 Consumer Group Statistics

Statistics are collected and analysed as per the customer groupings as described in the previous section. This information is used as a base to Nelson Electricity's pricing allocations as described further in this report. Information used for the 2022-2023 year is as follows:

- Number of Connections per group.

Number of Connections

Load Group	Connections
0	47
1	4334
2	4858
3	90
4	1
Total	9,330

- Anytime Maximum Demand per group

**Anytime Maximum Demand
(AMD) Based on NEL top 12
peaks**

Load Group	Peak kW
0	161
1	8,088
2	13,289
3	7,899
4	2,192
Total	31,629

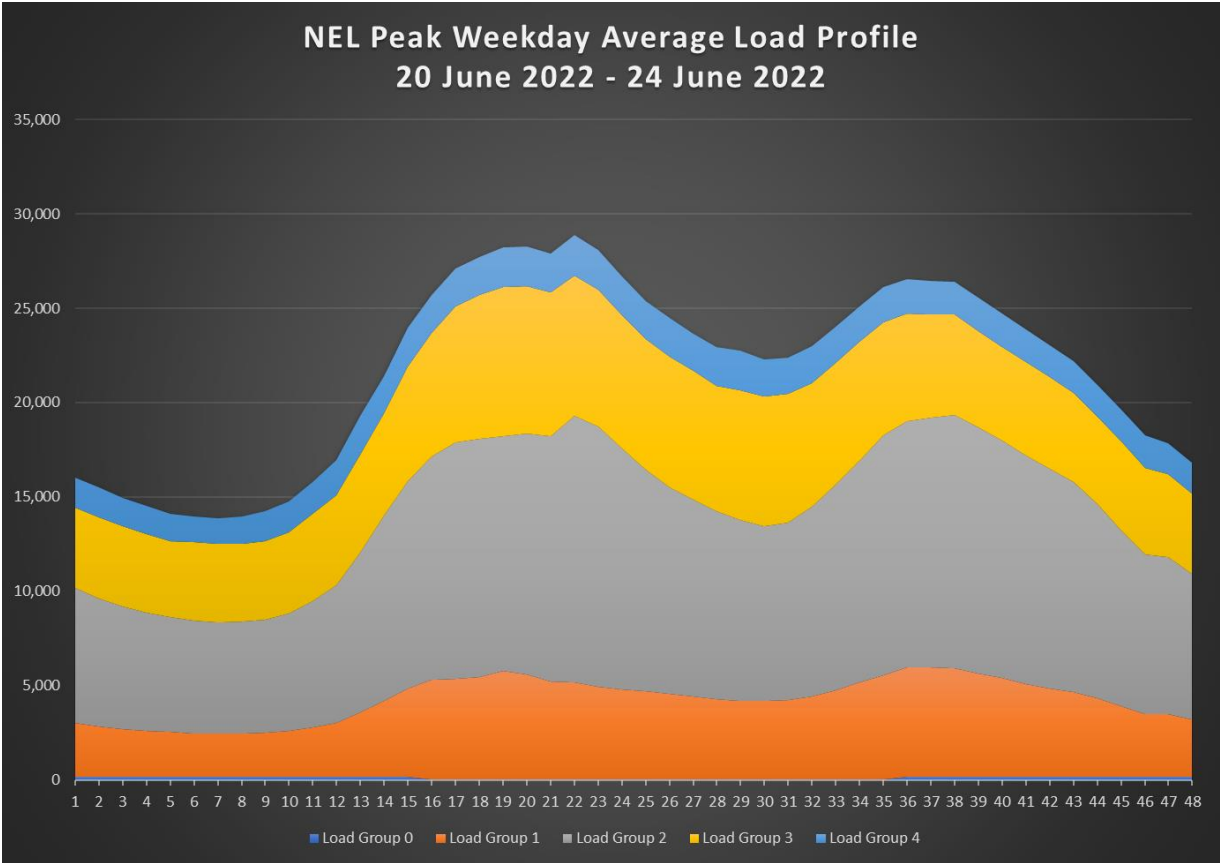
- Winter Demand Peak per group.

**Control Period Demand (Winter Demand)
kVA**

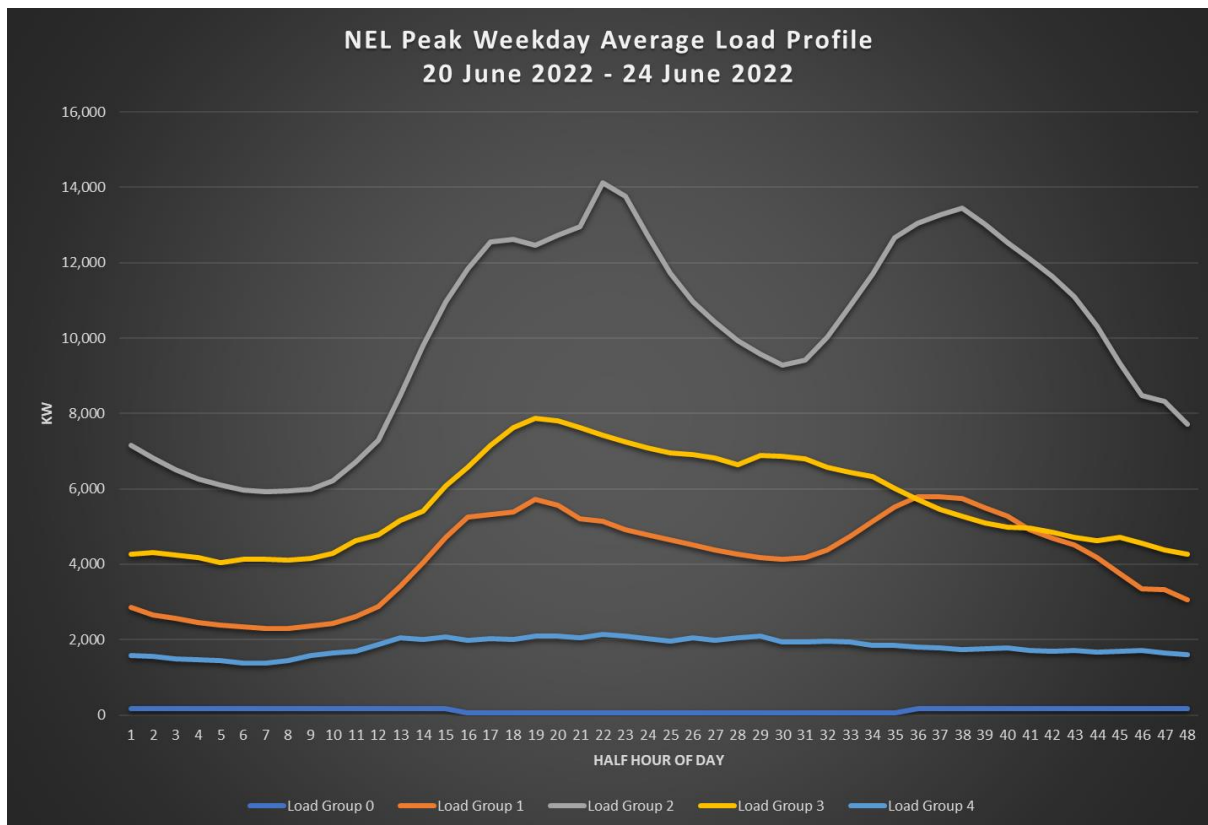
Load Group	8:30 am - 11:30 am	5:00 pm - 6:00 pm	CPD Allocation
0	50	106	64
1	5,368	5,416	5,380
2	12,987	13,105	13,017
3	7,539	5,877	7,123
4	2,071	1,828	2,010
Total	28,015	26,331	27,594

Nelson Electricity has a winter load that peaks between 8.30 am – 11.30 am and 5.00 pm – 6.00 pm. The morning load is predominantly commercial load with the morning residential load dropping off and the evening peak is typically influenced by the residential load with the commercial load dropping off. The statistics required are to ensure the right pricing signals are sent to each group and that charges are as fair and equitable as possible to all connections.

The Winter Demand is an important part to the allocation of Transmission Costs between groups. It is also important when allocating costs for local network in allocating costs based on load group contribution to peak demand and maximum loading on assets.



The graph below shows each load group contribution to the average peak winter load profile for the highest consumption week Monday 29 June 2020 – Friday 3 July 2020. The impact of load control of hot water during the weekday mornings can be seen in Groups 1 and to a lesser degree Group 2.



- MWh per group.

MWh			
Load Group	Winter	Summer	Total
0	332	357	688
1	12,044	10,706	22,750
2	29,142	28,142	57,284
3	18,369	23,246	41,615
4	6,297	7,184	13,481
Total	66,184	69,635	135,819

These consumption figures are estimated per Load Group with no loss allocation back to GXP. Winter months are May – September, Summer months are October – April. This is consumption only and is not offset by any distributed generation. The total consumption exported onto the Nelson Electricity network for the year ending December 2022 was 0.61MWh compared to 0.44 MWh for the previous 12 months.

- Regulatory Value of System Fixed Assets as at 31 March 2022 per group allocation

Asset Group	Regulatory Value of System Fixed Assets					
	0	1	2	3	4	Total
33kV Lines	\$16,854	\$1,002,071	\$2,451,103	\$1,463,066	\$433,421	5,366,516
Zone Sub	\$31,807	\$1,891,087	\$4,625,670	\$2,761,067	\$817,943	10,127,574
11kV Lines	\$24,327	\$1,571,448	\$3,662,899	\$2,111,707	\$375,345	7,745,726
11kV/400V Sub	\$28,905	\$2,051,322	\$5,041,543	\$2,007,285	\$74,330	9,203,385
400V Lines	\$117,249	\$2,335,515	\$5,753,129	\$1,295,125	\$0	9,501,021
Other	\$13,556	\$910,561	\$2,076,037	\$1,176,764	\$139,443	4,316,361
Total	\$232,699	\$9,762,003	\$23,610,381	\$10,815,015	\$1,840,482	\$46,260,583

Regulatory Asset Base Valuation allocation is assessed on each load group's utilisation of assets. As an example, Group 4 does not utilise any of the 400V lines so there is no value assigned.

- Cost of Capital

For the financial year commencing 1 April 2022 Nelson Electricity, being a price controlled EDB, has used the Commerce Commission's WACC for the five-year DPP price control period 1 April 2020 - 31 March 2025. This vanilla WACC of 4.23% is set at the 67th percentile.

Table 2: Values used to calculate WACC estimates for EDB DPP and Transpower IPP

Parameter	EDB and Transpower
Risk-free rate	1.12%
Average debt premium	1.60%
Leverage	42%
Asset beta	0.35
Equity beta	0.60
Tax adjusted market risk premium	7.0%
Average corporate tax rate	28%
Average investor tax rate	28%
Debt issuance costs	0.20%
Cost of debt	2.92%
Cost of equity	5.00%
Standard error of WACC	0.0101
Mid-point vanilla WACC	4.13%
Mid-point post-tax WACC	3.78%

*The numbers are rounded to two decimal points.

Based on the above input parameters, the Weighted Average Cost of Capital (WACC) is 4.23% of Regulatory Asset Base = \$1,957k.

8.3 Maximum Allowable Revenue

Nelson Electricity is a non-exempt EDB and as such the forecasted revenue cannot exceed the forecast allowable revenue as determined by the Electricity Distribution Services Default Price-Quality Path Determination 2020 (DPP3). The overall forecast allowable revenue from delivered line prices is \$8,409k down \$295k from the forecast allowable revenue for the year ending 31 March 2022 of \$8,704k.

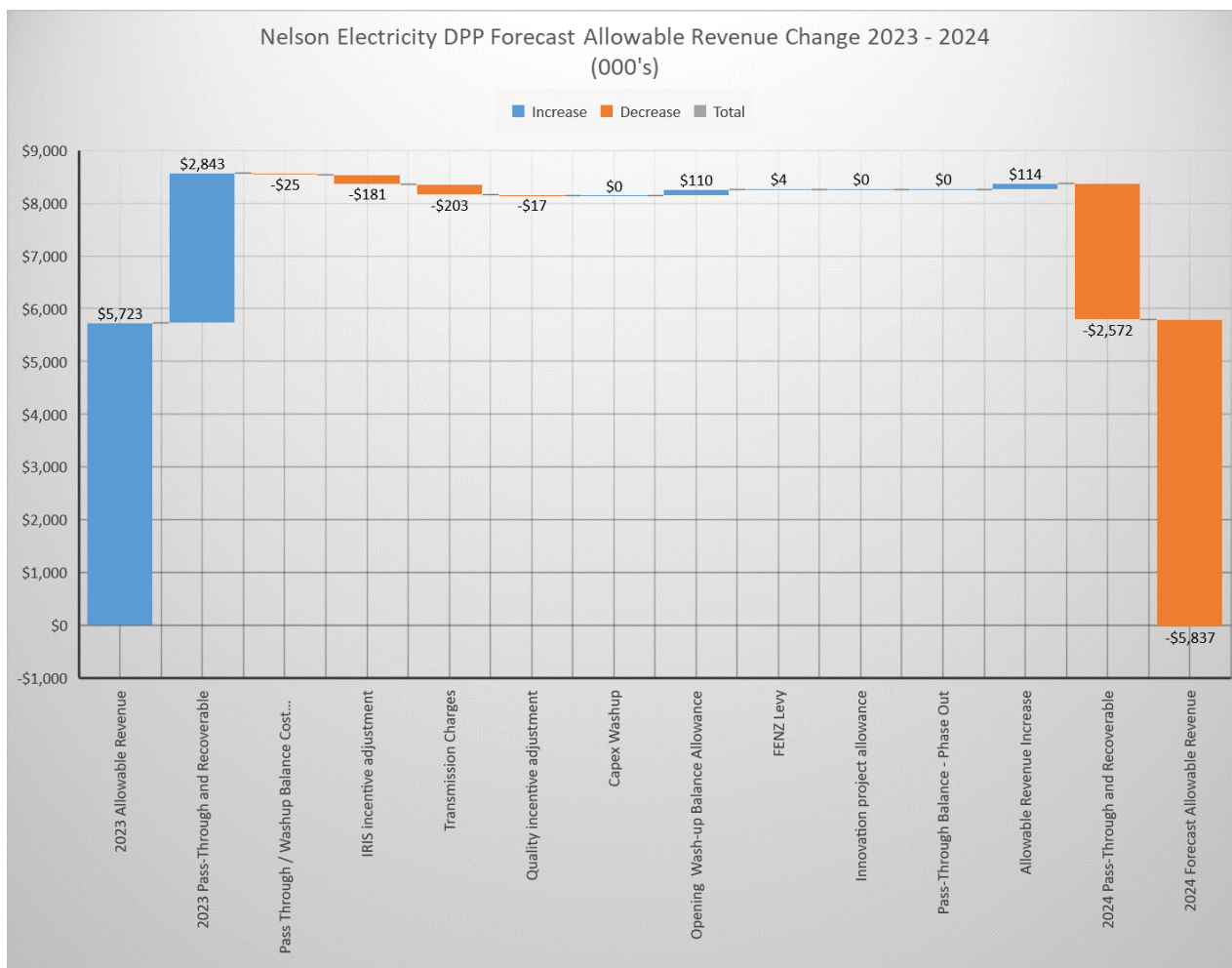
Forecast Allowable Revenue (000's)		
Forecast Net Allowable Revenue	=	\$5,837
Forecast Pass-Through and Recoverable	=	\$2,462
Opening Washup Balance	=	\$110
		\$8,409

Key Changes in Revenue Building Blocks

- **Forecast net allowable revenue.** The forecast net allowable revenue as determined by DPP3 \$5,837k up \$114k from \$5,723k for the year ending 31 March 2023.
- **Transmission Costs.** The forecasted transmission costs for the year is \$2,488k down \$203k from \$2,691k for the year ending 31 March 2023. The reduction is due to the changes in the TPM.
- **IRIS (incremental rolling incentive scheme) Incentive Adjustment.** The calculated IRIS adjustment is -\$211k down \$181k from -\$30k for the year ending 31 March 2023. The IRIS incentive adjustment varies from year to year based on the actual Capex and Opex levels compared to the Default Price Path allocations. The IRIS mechanism allows Nelson Electricity to retain any cost saving for 5 years after the saving is made. This gives a consistent, time-invariant incentive to make cost reductions.

The following building graph and table demonstrates the changes to the individual Forecast Allowable Revenue building blocks.

Pass-Through and Recoverable Cost Summary (000's)			
Forecast pass-through costs	2022-23	2023-24	Change
Rates on system fixed assets	\$37	\$41	\$4
Commerce Act levies	\$30	\$33	\$3
Electricity Authority levies	\$39	\$46	\$7
Utilities Disputes levies	\$6	\$6	\$1
Total forecast pass-through costs	\$111	\$126	\$15
Forecast recoverable costs	2022-23	2023-24	Change
IRIS incentive adjustment	-\$30	-\$211	-\$181
Transpower transmission charges	\$2,691	\$2,488	-\$203
New investment contract charges	\$0	\$0	\$0
System operator services charges	\$0	\$0	\$0
Avoided transmission charges - purchased assets	\$0	\$0	\$0
Distributed generation allowance	\$0	\$0	\$0
Claw-back	\$0	\$0	\$0
Catastrophic event allowance	\$0	\$0	\$0
Extended reserves allowance	\$0	\$0	\$0
Quality incentive adjustment	\$20	\$2	-\$17
Transmission asset wash-up adjustment	\$0	\$0	\$0
Reconsideration event allowance	\$0	\$0	\$0
Quality standard variation engineers fee	\$0	\$0	\$0
Urgent project allowance	\$0	\$0	\$0
Fire and emergency NZ levies	\$31	\$35	\$4
Capex Washup	\$21	\$21	\$0
Innovation project allowance	\$0	\$0	\$0
Total forecast recoverable costs	\$2,732	\$2,336	-\$396
Washups	2022-23	2023-24	Change
Washup Account Balance	\$135	\$110	-\$25
Pass-Through Balance Allowance			
Total Washup Costs	\$135	\$110	-\$25
Total Recoverable and Pass-Through	2022-23	2023-24	Change
	\$2,978	\$2,572	-\$406



8.4 Allocation and Recovery of Network and Transmission Charges

Network Delivery Prices are set to recover indirect operating costs, direct operating costs, depreciation, and cost of capital. Total cost recovery cannot exceed the Forecast Allowable Revenue as described in Section 8.3. The setting of the charges also considers historical charging practices and methodologies.

The company annual revenue requirements for 2023/2024 are:

Operating Costs (Network R&M)	\$911k
Transmission Costs	\$2,487k
Overhead Costs	\$1,847k
Depreciation	\$1,896k
Target Return (before tax)	\$1,213k

With Nelson Electricity being a small predominantly urban network there was no need to sectionalise it into separate pricing areas. There is, however, one rural uneconomic line supplying a small number of consumers of which a separate pricing option is being introduced in 2023.

8.5 Cost Recovery per Load Group

Following is a table outlining the cost recoveries per load group.

Load Group	Operating	Transmission	Overhead	Depreciation	Target Return	Total
0	\$46,534	\$12,444	\$6,790	\$9,537	\$21,678	\$96,984
1	\$192,976	\$515,261	\$692,769	\$400,098	\$44,632	\$1,845,735
2	\$470,169	\$1,054,024	\$875,086	\$967,677	\$899,502	\$4,266,456
3	\$191,233	\$693,039	\$216,168	\$443,256	\$221,358	\$1,765,055
4	\$9,968	\$212,111	\$55,059	\$75,433	\$27,430	\$380,000
Total	\$910,879	\$2,486,879	\$1,847,000	\$1,896,000	\$1,213,472	\$8,354,230

The methodology used for the above cost apportionment is as follows:

Operating Costs – Operating costs is the Operational Expenditure Budget that covers both the planned and unplanned network R&M expenditure on the network. The Operational Expenditure Budget is split into the different asset types as per the Regulatory Asset Value of System Fixed Assets table groups. The asset group expenses are then allocated to each load group first based on whether the Group utilises that class of asset (eg; Group 4 does not utilise the 400V network so does not contribute towards those associated costs) then through the assessed balance of each group's kWh consumption (60%) and Winter Demand contribution (40%). This percentage allocation attempts to provide a balance between a Groups peak demand utilisation and overall usage.

Some re-balancing is required for load group specific costs, eg; Group 0 where actual Council streetlighting associated maintenance costs of \$40,000 are directly allocated to the associated tariff. This allocation is offset against Group 1 and 2 apportioned based on kWh.

Regulatory Value and Operating Cost Percentage Allocation						
	0	1	2	3	4	Total
33kV Lines	0.31%	18.67%	45.67%	27.26%	8.08%	100.00%
Zone Sub	0.31%	18.67%	45.67%	27.26%	8.08%	100.00%
11kV Lines	0.31%	20.29%	47.29%	27.26%	4.85%	100.00%
11kV/400V Sub	0.31%	22.29%	54.78%	21.81%	0.81%	100.00%
400V Lines	1.23%	24.58%	60.55%	13.63%	0.00%	100.00%
Other	0.31%	21.10%	48.10%	27.26%	3.23%	100.00%
Operational Cost Allocation						
Asset Group	0	1	2	3	4	Total
33kV Lines	\$33	\$1,946	\$4,761	\$2,842	\$842	\$10,424
Zone Sub	\$152	\$9,031	\$22,090	\$13,185	\$3,906	\$48,364
11kV Lines	\$346	\$22,332	\$52,055	\$30,010	\$5,334	\$110,077
11kV/400V Sub	\$154	\$10,917	\$26,831	\$10,683	\$396	\$48,980
400V Lines	\$4,927	\$98,150	\$241,776	\$54,428	\$0	\$399,282
Other	\$923	\$61,969	\$141,286	\$80,085	\$9,490	\$293,753
Sub Total	\$6,534	\$204,346	\$488,798	\$191,233	\$19,968	\$910,879
Reallocation	\$40,000	-\$11,370	-\$18,630		-\$10,000	\$0
Total	\$46,534	\$192,976	\$470,169	\$191,233	\$9,968	\$910,879

- Transmission Costs – Transmission costs are an unavoidable cost. It covers the upstream costs from our sub-transmission connection points at STK0331. The transmission cost allocation has

changed due to the changes in the Transmission Pricing Methodology (TPM) that apply from 1 April 2023. Transmission costs are now mostly fixed but are allocated between Load Groups in alignment with the Electricity Authority Practice Note and ENA recommended approach to passing through of transmission charges.

Allocation (000's)		
Transmission Charge	Load Group Allocation	Value
Benefit Based Charge	kWh	\$325
Residual Charge	kWh/AMD	\$1,958
Connection Charge	AMD	\$194
Transitional Cap	kWh/AMD	\$9
		\$2,486

The methodology for recovery of transmission charges has changed with the change in the TPM. The proportion of transmission cost recovery from consumers is changing significantly from 22% fixed and 78% variable for the year ending 31 March 2023 to 70% fixed to 30% variable from 1 April 2023. Transmission charge recovery from consumers reflects the new TPM as far as practical with a high proportion being fixed in nature. Group 1 fixed cost recovery proportion is limited by the LFC Regulations. All variable cost recovery in Groups 1 and 2 is through uncontrolled pricing options, there are now no transmission charges on any controlled pricing options. For Groups 3 and 4, transmission costs are recovered via a mixture of Fixed, Capacity, Winter Control Period Demand charge (70%) and a variable kWh charge (30%).

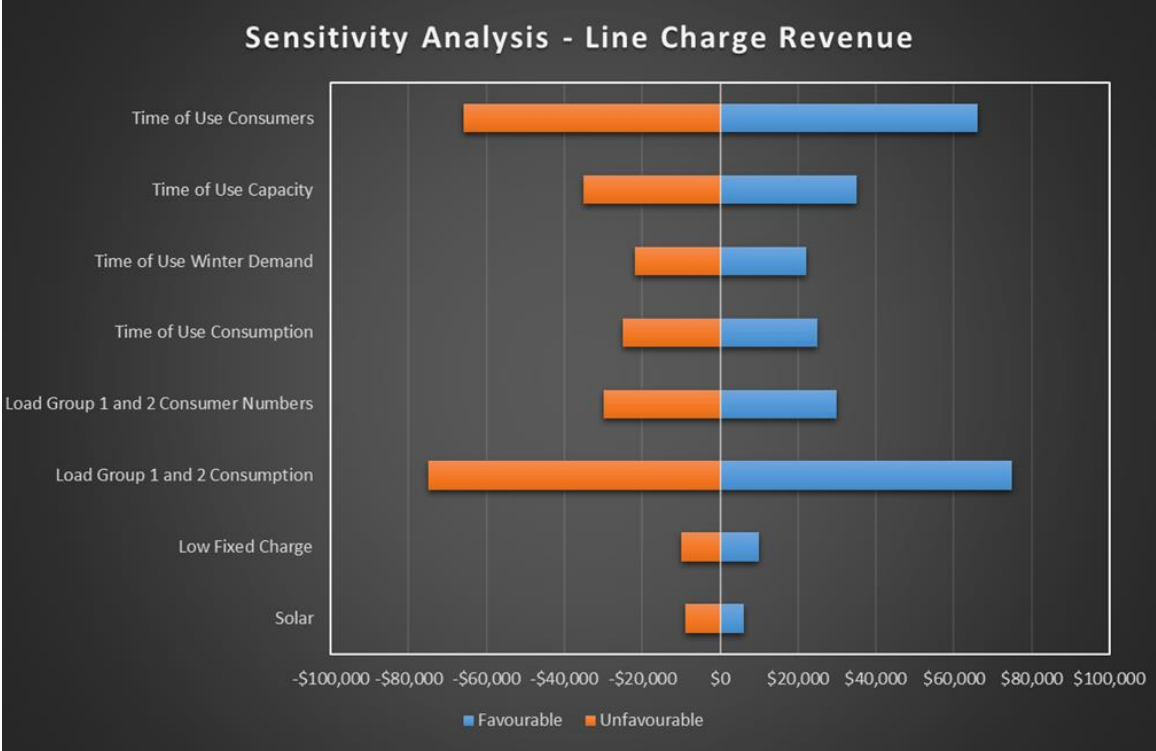
Fixed V's Variable	Fixed		Variable		Total
	%	\$	%	\$	\$
Group 0	100%	\$12,390	0%	\$54	\$12,444
Group 1	46%	\$237,000	54%	\$278,261	\$515,261
Group 2	81%	\$857,136	19%	\$196,887	\$1,054,024
Group 3	63%	\$434,606	37%	\$258,433	\$693,039
Group 4	100%	\$212,111	0%	\$0	\$212,111
Total	70%	\$1,753,244	30%	\$733,635	\$2,486,879

The methodology for passing-on settlement residual rebates (Loss Rental Rebates) is described in Section 18.

- Overhead Costs – Are apportioned by using two measures. The number of network connections and the control period demand of the load group. This gives a balance of spreading overhead costs between the business of selling capacity and the number of consumers connected.
- Depreciation – This is apportioned by using the assessed depreciation using the NEL Regulatory Asset Base model as a base and follows the same rationale as Operating Costs (except without re-allocation of Load Group specific costs).
- Target Return - This is apportioned to load groups as per the Regulatory Asset Base % split per load group as per the rationale of the operating costs. It is, however, important to note that the Regulatory Asset Base valuation for assets installed prior to 2004 still undervalues the underground network value and so the target return takes this into account.

8.6 Sensitivity Analysis

The Nelson Electricity revenue estimate for 2023-2024 is \$8,354k. There is a potential variation of 3.1% or a range from \$8,100k to \$8,650k for the year..



8.7 Fixed v’s Variable Charges

The proportion of charges that are deemed by Nelson Electricity as fixed or variable had previously been set based on historical pricing. This has now been changed to align with the Electricity Authority’s Distribution Pricing: Practice Note -Second Edition v 2.2, 2022 (Practice Note).

The only major variation is the provision of a LFC price option for Residential consumers as required under the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. This issue is slowly being remedied as the LFC is phased out.

Nelson Electricity has reviewed the Electricity Authority’s Practice Note in attempting to determine the revenue required from pricing signals then recover remaining revenue through using pricing that least-distorts choices. The initial outcome was that with no constraints on the network in the short term, that the pricing signals required should be very low and result in 10% to 20% of revenue derived through variable charges and the rest made up of some form of fixed charges. Nelson Electricity’s concern, however, is that price signals will need to be stronger and cater for the medium/long term to be confident that long-term decisions are in the best interests of customers. It is determined that a transitional approach be implemented to reach truly cost reflective pricing. The assessed proportion of revenue from variable charges in 2023-2024 is 36% down from 41%.

Groups 1 and 2 have a higher variable proportion while groups 3, 4, and 5 have a higher fixed proportion. Refer to the table below.

Fixed V's Variable	Fixed		Variable		Total
	%	\$	%	\$	\$
Group 0	100%	\$96,808	0%	\$176	\$96,984
Group 1	39%	\$711,000	61%	\$1,134,735	\$1,845,735
Group 2	65%	\$2,766,979	35%	\$1,499,477	\$4,266,456
Group 3	81%	\$1,423,461	19%	\$341,594	\$1,765,055
Group 4	100%	\$380,000	0%	\$0	\$380,000
Total	64%	\$5,378,248	36%	\$2,975,982	\$8,354,230

Consumer behaviour as a response to network pricing is limited. The line price revenue represents only 30% of the total electricity invoice consumers receive from electricity retailers so unless a network can significantly amplify or exaggerate the pricing differential levels then the consumer behaviour will be based on what the electricity retailer wants to achieve.

Nelson Electricity is in the business of selling electrical capacity to consumers and most of its costs as identified in Section 6.4 are fixed. If the true proportion of fixed and variable costs were charged in the same proportions to all consumers, the fixed charge proportion of Groups 0, 1 and 2 consumers would increase significantly with the variable charges reduced. The incremental cost of any consumer using more kWhs, while not increasing their peak demand, is extremely low compared to a consumer wanting more capacity where there is a cost associated with the increases in peak demand.

For further breakdown on the revenue influence of specific prices, refer to Section 14 Price / Quantity / Revenue Schedule.

- **Load Group 0 – Unmetered and Builders Temporary**

Builders Temporary (metered) - Network costs are broken down into the following:

- Daily Price (Fixed)
- Uncontrolled kWh Price

For the average Builders Temporary, fixed prices recover approximately 60% of total network costs.

Unmetered Supply – Network costs are fully fixed with no variable component.

Load Group 0 prices are predominantly fixed given that the low consumption does not make metering practical or economic for retailers. The only metered load in Group 0 is for builder's temporary connections. This type of connection is in Group 0 as the fuse size is low (limited to single phase 30 amps), the consumption is typically low and the load characteristics do not fit other load groups and the revenue impact is low.

- **Load Group 1 and 1P – Residential Consumers (LFC Options)**

Network costs are broken down into the following:

- Capacity Supplied Price is based on connection capacity of 15kVA
- Variable kWh Price. This price value depends on whether the load is controlled by ripple control or uncontrolled. The controlled prices are significantly lower than the uncontrolled price as Nelson Electricity can ensure they are turned off at peak times therefore reducing potential network stress and other peak demand associated costs. Variable charges contribute 28% of the total line charge revenue for the Load Group. The transmission costs are allocated to the fixed and uncontrolled kWh pricing options as per Section 8.4.
- There are two controlled kWh pricing options:
 - a. Controlled (Hot water) – This is a key network control option to control supply to all hot water cylinders on the network. This can manage up to 10% of network load at peak demand times approximately 3MW. Typically, supply is only controlled during the winter peak demand times to minimise the Maximum Demands that will assist in minimizing transmission connection costs. Also used for other emergency load management purposes.
 - b. Night Only - This is an option for consumers that can utilise electricity in off-peak times between 11.00 pm and 7.00 am, typically used for larger hot water cylinders and night storage heaters.
- Distributed Generation. A price is included based on kWh exported onto the NEL network. This price recovers some of the costs associated with the auditing and safety aspects of the distributed generation connection.

For the average Group 1 customer, fixed prices recover approximately 39% of total network costs.

This Group exists to comply with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. Any eligible residential consumer can opt to be in this group. Typically, there has been approximately 200 to 300 consumers per year shifting from Group 2 to Group 1, this has reduced significantly in the last 2 years. The average annual residential consumption is also reducing and for Nelson Electricity it is now approximately 6,750 kWh per year.

- **Load Group 2, 2P and 2R – Connections from 15kVA – 150kVA (Residential and Commercial)**
Network costs are broken down into the following:

- Capacity Supplied Price (based on fuse capacity (in kVA).
- Variable kWh Price. This price value depends on whether the load is controlled by ripple control or uncontrolled. The controlled prices are significantly lower than the uncontrolled price as Nelson Electricity can ensure they are turned off at peak times, therefore, reducing potential network stress and other peak demand associated costs. Variable charges contribute 25% of the total line charge revenue for the Load Group. The transmission costs are allocated to the fixed and uncontrolled kWh pricing options as per Section 8.4.
- There are two controlled kWh pricing options:
 - a. Controlled (Hot water) – This is a key network control option to control supply to all hot water cylinders on the network. This can manage up to 10% of network load at peak demand times approximately 3MW. Typically, supply is only controlled during the winter peak demand times to minimise transmission connection costs. Also used for other emergency load management purposes.

- b. **Night Only** - This is an option for consumers that can utilise electricity in off-peak times between 11.00 pm and 7.00 am, typically used for larger hot water cylinders and night storage heaters.
- **Distributed Generation.** A price is included based on kWh exported onto the NEL network. This price recovers some of the costs associated with the auditing and safety aspects of the distributed generation connection.

For the average Group 2 customer, capacity-based charges recover approximately 65% of total network costs. All residential and business consumers are eligible from 15kVA up to 150kVA. It is designed so that the larger the fuse at the network connection point then the higher the fixed charges. The variable charges remain unchanged.

This Group has a price design to encourage consumers to manage their electricity use by providing an incentive to lower fused capacity. There is one current limitation with this design due to the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004. The Regulation ensures that for every pricing option a residential consumer can be eligible for, there must be a pricing option they can shift to that meets the requirements of the regulations ie; fixed daily charge of no greater than 45 cents per day. To meet the regulation Nelson Electricity would require a significant increase in line pricing options by 40 (one set of four for each of the 10 potential fuse size combinations). To comply with the requirements and remove the potential complexity, the residential consumers in Group 2 (3,471) currently have their fused capacity set at 15kVA while non-residential (1,373) have capacity based on actual fuse size.

- **Load Groups 3 – Large Commercial**

This Price Group is designed for the larger installations on the network. These sites must have Time of Use metering installed. Nelson Electricity can set network prices based on the individual site configuration and usage pattern more accurately. The prices in this category are explained below.

1. **Metered Installation.** This is a fixed priced per connection designed to capture the fixed network admin costs associated with each connection. The value is the same no matter what size.
2. **Winter Demand.** The Winter Demand is a \$/kW/day fixed price and is a method of apportioning transmission and network peak demand costs. The measure is the single highest half hour kVA demand recorded in the months of June, July, and August between 8.30 am-11.30 am and 5.00 pm-6.00 pm. The winter demand assessment period excludes weekends and public holidays. The winter demand value is used for billing purposes from the October month for the following 12 months until reset again the after the following winter.
3. **Capacity Supplied.** Capacity Supplied is a \$/kVA/day fixed price and is the actual size of the connection to the Network (either fuse size or transformer size). This represents the maximum demand the site can draw from the network. This charge is used to recover local network costs.
4. **Energy.** The Energy charge is a variable price based on the total energy consumption for the connection. This is used to recover both transmission and network costs.

5. **Power Factor.** This monthly variable price is used to encourage consumers to maintain a power factor of greater than 0.95. The charge is for the kVA_r required at peak time to bring the power factor up to 0.95. A charge is not applied if power factor at peak is > 0.95.
6. **Distributed Generation.** This is a new variable price that is for kWh exported onto the network. This recovers costs associated with the auditing and safety aspects of the distributed generation connection.

8.8 Chargeable Capacity

The following is the typical fuse size combinations and associated capacity rating accepted at a Nelson Electricity Network Connection Point. Larger connections are on a case-by-case basis.

Fuse Rating Table

No. of Phases	Fuse size (Amps)	kVA Rating
3	30	15
2	40	15
3	40	28
1	60	15
2	60	30
3	60	45
1	80	20
2	80	40
3	80	60
1	100	23
2	100	46
3	100	69
3	125	87
3	150	105
3	160	110
3	200	138

The two phase 40 amp and three phase 30-amp supplies are assessed at the minimum capacity of 15kVA to cater to those connections on multiple phases prior to the capacity charges coming into effect.

8.9 Changing Pricing Plan Limitations

Where a consumer has a choice of pricing plan, Nelson Electricity reserves the right to limit changes between pricing plans to one change in any 12-month period eg; Nelson Electricity offers the Low Fixed Charge plans (Pricing Category 1 and 1P) to qualifying residential connections and a standard plan (Pricing Category 2 and 2P) for residential connections. This condition is included in the Nelson Electricity Use of System Agreement for the purposes of managing the risk of consumers shifting principally between the regulatory imposed Group 1 Pricing and the Group 2 Pricing to take advantage of the summer/winter differences.

9. Future Changes

Nelson Electricity will continually review the existing pricing structure to ensure it is providing the right pricing signals for consumers that will assist in running the electricity network as efficiently as possible.

Areas for consideration are:

Electric Vehicle Charging Pricing Option

A separate electric vehicle charging option that incentivises charging out of peak times is being considered. This could either be controlled via Ripple Control during peak demand times or be time controlled to only be on during late evenings through to early morning. The one complication is that occasionally consumers may require their Electric Vehicles to be charged outside of these control periods and there needs to be a mechanism in place to allow this to occur.

Load Groups 1 and 2 - Peak/Off-Peak Pricing Differential

Nelson Electricity will be reviewing the required pricing differentials between Peak and Off-Peak times to ensure consumers are provided the right level of incentives as we progress towards the forecasted growth in the medium to long term.

10. Non-Standard Contracts

Nelson Electricity will consider offering a non-standard contract to consumers it can be demonstrated that there is a benefit to both parties to do so. The key consideration would be if the consumer is large enough typically over 1,000kVA connected capacity and can manage peak load for the benefit of minimising any peak demand times, either transmission or network related.

The management of peak load could be through load shedding or utilisation of distributed generation.

Currently there are two non-standard contracts in place and all other consumers are charged as per the pricing schedule attached to this document. The expected revenue to be received in the coming year is \$280k from the two non-standard contracts.

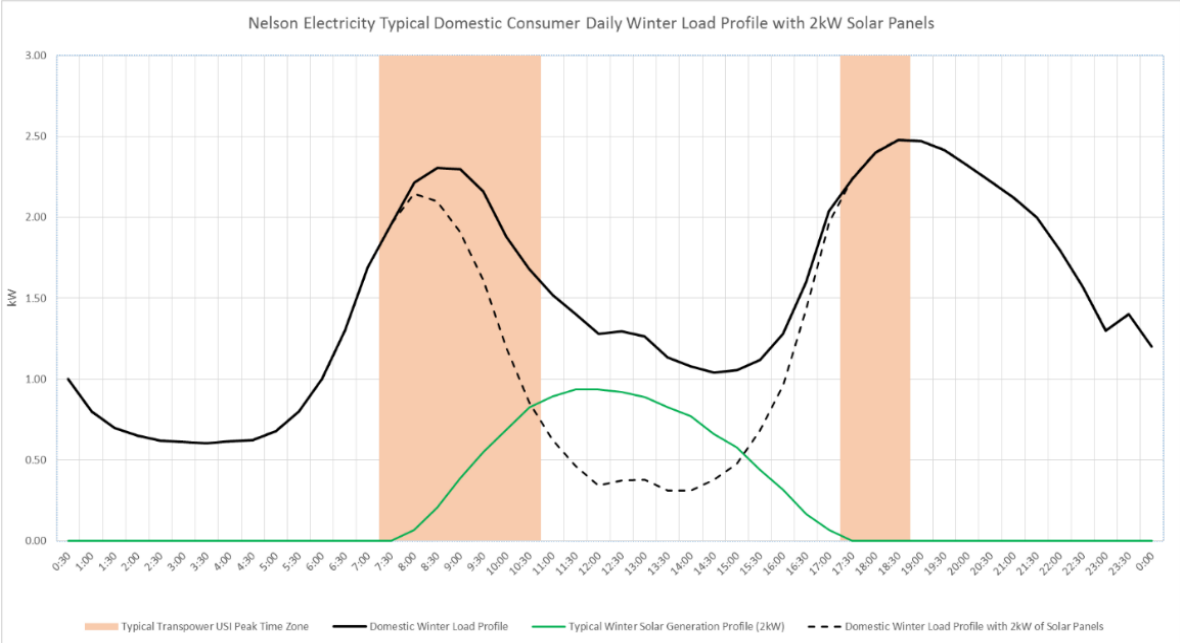
In determining a non-standard contract line charge, Nelson Electricity would determine the potential reduction in costs associated with a consumer connection if they were able to manage their load in a particular way. An example is a consumer being able to manage load in the peak demand times. This may result in a lowering of transmission connection charges for Nelson Electricity which the consumer could benefit from.

Nelson Electricity will consider any application from a consumer for a non-standard contract if it can be demonstrated that there is a benefit for both parties to do so, whether it be due to load management, distributed generation, or bypass potential.

11. Distributed Generation

Nelson Electricity allows the connection of distributed generation to its network. There are additional requirements for these connections to satisfy Nelson Electricity that these connections are safe. The requirements are posted on the Nelson Electricity Website www.nel.co.nz.

While these connections can inject electricity back into the Nelson Electricity network the timing of this, if through solar, is not at a time when Nelson Electricity would benefit and assist in reducing network costs. Nelson Electricity infrastructure is designed to meet the peak capacity of the network which is on the coldest winter mornings when there is high level of cloud cover. The benefit of any solar distributed generation is negligible.

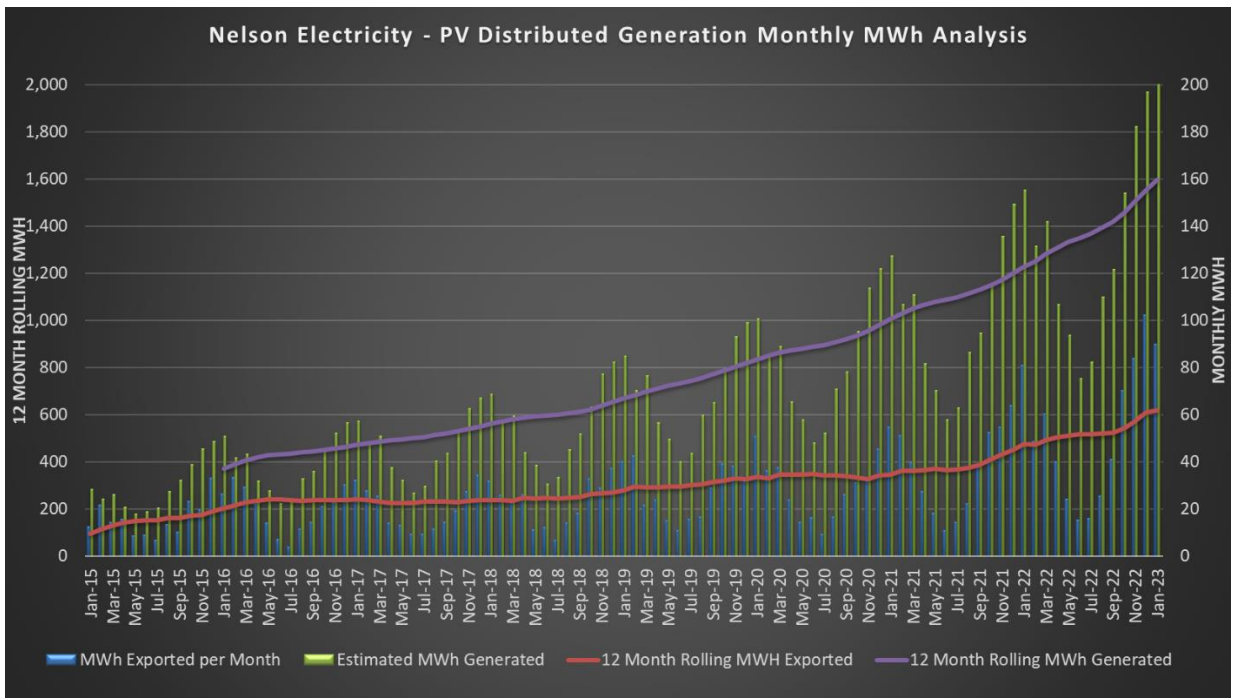
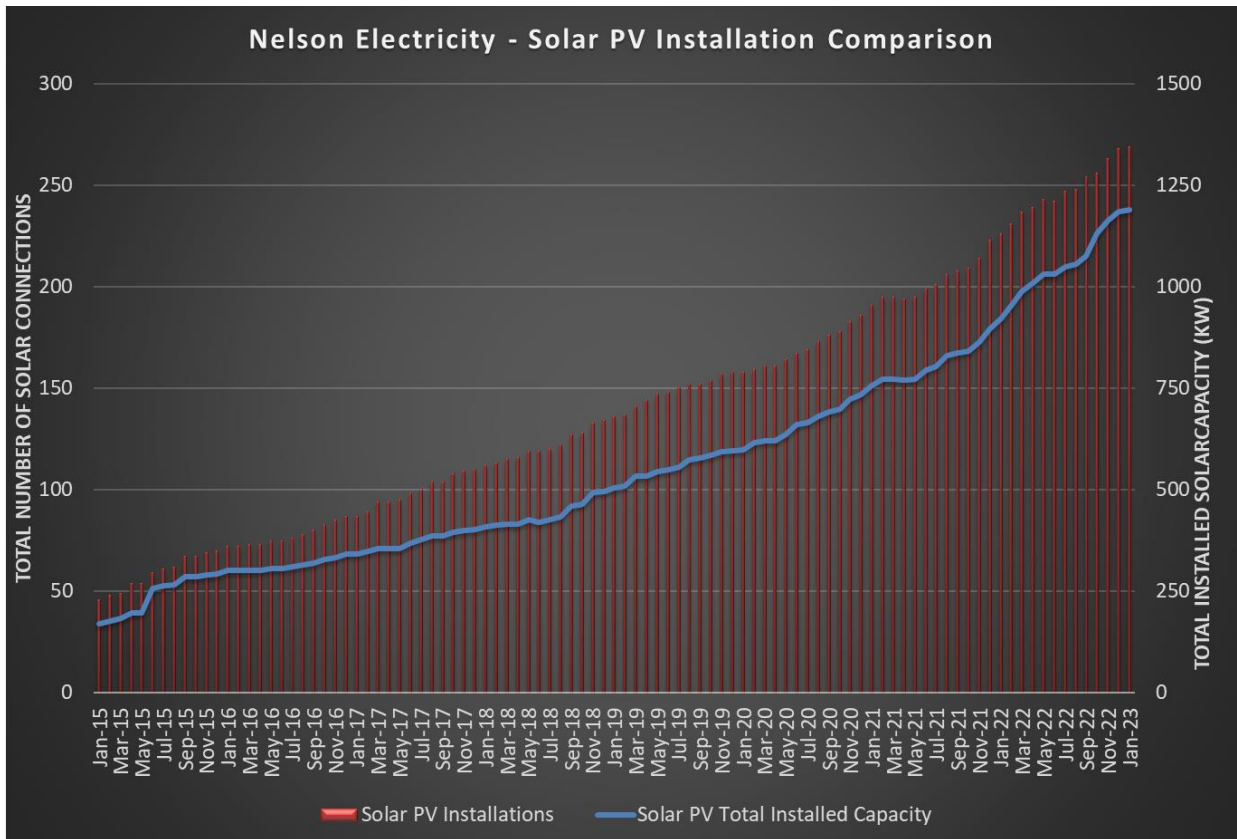


For this reason, Nelson Electricity does not offer any pricing benefit for distributed generation connections for either local line or transmission charges. Analysis of existing installations is being undertaken to ensure that any exported electricity is within the related voltage limits and of appropriate quality.

Nelson Electricity has been reviewing the costs associated with processing new distributed connections and auditing of the connections as there are additional costs associated with managing these connections to ensure they comply with appropriate standards. A new price option was created from 1 April 2014 for the exporting of kWh on to the Nelson Electricity network for Groups 1 and 2, and now introduced to Group 3 from 1 April 2018. Although the level of the price is only 0.5 cents per kWh, this is designed to capture some of the safety audit costs of distributed generation sites. As an example, the annual audit costs are approximately \$15 per year and the 0.5 cents per year will only recover \$10 per year at 2,000kWh per site.

As the installed price of distributed generation decreases, the financial viability for consumers to install increases. Nelson Electricity is mindful that connections that have solar PV installed do not contribute fairly to their cost to supply electricity as their peak electricity usage in the middle of winter has not materially changed as per the graph above. Any electricity consumer looking to invest in distributed generation must take this into consideration.

There are currently 269 distributed generation installations on the network (as of January 2023) totalling 1,190kW of generating capacity. There were 43 new installations in the last 12 months. It is expected that the numbers will slowly increase as the installed price decreases.



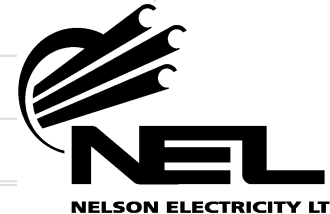
12. Electricity Networks Association – Pricing Guidelines for Electricity Distributors

The Electricity Networks Association in New Zealand in 2015 completed a Distribution Pricing Guideline and updated in 2016 and again in September 2022 for the purpose of the assisting electricity distribution businesses to describe and present their distribution prices in a consistent manner.

This Pricing Methodology as far as practical has been written to be in line with the guidelines to provide increased consistency with other networks. It is expected that over time that as the guidelines get developed further, then this pricing methodology be improved further.

13. Pricing Schedule

Nelson Electricity Ltd Delivery Price Schedule From 1 April 2023



Nelson Electricity Ltd is adjusting delivery prices effective 1 April 2023.

The prices in this schedule are used to charge electricity retailers for the delivery of electricity over the Nelson Electricity electricity network. Electricity retailers determine how to allocate this cost to gether with energy, metering and other retail costs when setting the retail prices that appear on a customer's power account.

Nelson Electricity distributes electricity to connections in the central Nelson city including most of the Port, Port Hills, Nelson South, Toi Toi, Brook, Wood, Nelson East and CBD areas.

Nelson Electricity - New Pricing				New Delivery Prices from 1 April 2023		Equivalent Existing Prices to 31 March 2023	
Price Code	Description	Consumer Numbers	Units	Distribution Price	Transmission Price	Delivery Price	Delivery Price
Load Group 0							
Builders Temporary (7kVA)							
0-BT	Builders Temp - Fixed	9	\$/day	0.6500	0.1500	0.8000	0.8000
0-BT	Builders Temp - Anytime		\$/kWh	0.0560	0.0250	0.0810	0.0810
Unmetered Connection (< 1 kW)							
0-UM	Unmetered - Fixed	37	\$/day	0.1500	0.0000	0.1500	0.1500
0-UM	Maximum Demand		\$/kW/day	0.8500	0.1500	1.0000	0.9700
Streetlighting							
0-SL	Streetlight	1	\$/day	196.5000	28.50	225.00	219.00
Load Group 1 (NHH Metering Only)							
Residential Low Fixed Charge (15kVA)							
1-FIXED	Fixed	563	\$/kVA/day	0.0200	0.0100	0.0300	0.0200
1-24HR	Anytime		\$/kWh	0.0395	0.0175	0.0570	0.0675
1-WATER	Controlled (Hot Water)		\$/kWh	0.0330	0.0000	0.0330	0.0425
1-NIGHT	Night Rate (11pm-7am)		\$/kWh	0.0280	0.0000	0.0280	0.0365
1-DG	Distributed Generation		\$/kWh	0.0050	0.0000	0.0050	0.0050
Load Group 1P (Peak/Off-Peak) - (HHR Metering)							
Residential Low Fixed Charge (15kVA)							
1P-FIXED	Fixed	3771	\$/kVA/day	0.0200	0.0100	0.0300	0.0200
1P-PEAK	Peak		\$/kWh	0.0455	0.0175	0.0630	0.0675
1P-OFFP	Off Peak		\$/kWh	0.0305	0.0175	0.0480	0.0675
1P-WATER	Controlled (Hot Water)		\$/kWh	0.0330	0.0000	0.0330	0.0425
1P-NIGHT	Night Rate (11pm-7am)		\$/kWh	0.0280	0.0000	0.0280	0.0365
1P-DEF	Default		\$/kWh	0.0395	0.0175	0.0570	0.0675
1P-DG	Distributed Generation		\$/kWh	0.0050	0.0000	0.0050	0.0050
Load Group 2 (from 15kVA to 150kVA) - (NHH Metering Only)							
General - Residential and Commercial							
2-FIXED	Fixed	874	\$/kVA/day	0.0490	0.0220	0.0710	0.0710
2-24HR	Anytime		\$/kWh	0.0260	0.0040	0.0300	0.0330
2-WATER	Controlled (Hot Water)		\$/kWh	0.0060	0.0000	0.0060	0.0080
2-NIGHT	Night Rate (11pm-7am)		\$/kWh	0.0020	0.0000	0.0020	0.0020
2-DG	Distributed Generation		\$/kWh	0.0050	0.0000	0.0050	0.0050
Load Group 2P (Peak/Off-Peak from 15kVA to 150kVA) - (HHR Metering)							
General - Residential and Commercial							
2P-FIXED	Fixed	3980	\$/kVA/day	0.0490	0.0220	0.0710	0.0710
2P-PEAK	Peak		\$/kWh	0.0290	0.0040	0.0330	0.0330
2P-OFFP	Off Peak		\$/kWh	0.0200	0.0040	0.0240	0.0330
2P-WATER	Controlled (Hot Water)		\$/kWh	0.0060	0.0000	0.0060	0.0080
2P-NIGHT	Night Rate (11pm-7am)		\$/kWh	0.0020	0.0000	0.0020	0.0020
2P-DEF	Default		\$/kWh	0.0260	0.0040	0.0300	0.0330
2P-DG	Distributed Generation		\$/kWh	0.0050	0.0000	0.0050	0.0050
Load Group 2R - (Remote - Fringed Hill)							
Fringed Hill - Commercial							
2R-FIXED	Fixed	4	\$/kVA/day	0.0840	0.0220	0.1060	0.0710
2R-24HR	Anytime		\$/kWh	0.0260	0.0040	0.0300	0.0330

Load Group 3 LARGE COMMERCIAL (up to 2400kVA)							
TIME OF USE		90					
3-FIXED	Metered Installation		\$/day	14500	0.0000	1.4500	1.0000
3-WD	Winter Demand (kVA)		\$/kVA/day	0.1080	0.0270	0.1350	0.1680
3-24HR	Energy		\$/kWh	0.0020	0.0080	0.0100	0.0120
	Capacity Supplied (one of)						
T-03	T-03	16kVA – 42kVA	\$/day	16800	0.84	2.52	2.06
T-04	T-04	43kVA – 69kVA	\$/day	2.7600	138	4.14	3.39
T-05	T-05	70kVA – 110kVA	\$/day	4.4000	2.20	6.60	5.40
T-06	T-06	111kVA – 138kVA	\$/day	5.5200	2.76	8.28	6.78
T-07	T-07	139kVA – 218kVA	\$/day	8.7200	4.36	13.08	10.70
T-08	T-08	219kVA – 300kVA	\$/day	12.0000	6.00	18.00	14.73
T-09	T-09	301kVA – 500kVA	\$/day	20.0000	10.00	30.00	24.55
T-10	T-10	501kVA – 750kVA	\$/day	30.0000	15.00	45.00	36.83
T-11	T-11	751kVA – 1000kVA	\$/day	40.0000	20.00	60.00	49.10
T-12	T-12	1001kVA – 1500kVA	\$/day	60.0000	30.00	90.00	73.65
T-13	T-13	1501kVA – 2000kVA	\$/day	80.0000	40.00	120.00	98.20
T-15	T-15	2400kVA	\$/day	96.0000	48.00	144.00	117.84
3-DG	Distributed Generation		\$/kWh	0.0050	0.0000	0.0050	0.0050
3-PF	Power Factor <0.95		\$/kVAr/mth	6.5000	0.0000	6.5000	6.5000
All prices exclude GST. All prices as shown above are also available from our website www.nel.co.nz							
Pricing Guide - Details on how these delivered prices are applied are included in our Pricing Guide which is available on our website.							
Load Group 0 - Loads that meet Electricity Authority Unmetered Load Guidelines and Metered Builders Temporary Supplies (Builders Temp > 7kVA use Load Group 2).							
Load Group 1 - Residential households (principal place of residence only) with connection capacity of 15kVA using less than 8,000kWh per year as required to comply with the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.							
Load Group 2 - Available to all residential and commercial connections with capacity from 15kVA to 150kVA.							
Load Group 1 & 2 - All existing residential households have an assessed connection capacity of 15kVA.							
Load Group 3 - Available to any large commercial connections up to 2400kVA with Time of Use metering.							
Load Group 1, 2 and 3 - Distributed Generation charge is for electricity exported into the Nelson Electricity network.							
Any questions about the line charges, please email us at enquiry@nel.co.nz , or phone (03) 546-0486.							

14. Price / Quantity / Revenue Schedule

Total Revenue Table using 31 March 2024 Prices and 2023/2024 Quantities

Number of Days:		366											
Tariff or Fee	Number of ICPs at 31/03/2024	Billed kWh at 31/3/2024	Billed kVA at 31/3/2024	Billed Days at 31/3/2024	Distribution Charges				Notional Distribution Revenue (\$)		Total Revenue (\$)		
					Fixed			Variable (c/kWh)	Fixed	Variable	P ₂₀₂₄	Q ₂₀₂₄	
					\$/day	c/kVA/day	Other						
Group 0													
Streetlights	1	570,205	-	366	225.00	0.00	0.00	0.00	82,350	-	82,350		
Unmetered Fixed	37	-	-	13,542	0.15	0.00	0.00	0.00	2,031	-	2,031		
Unmetered Capacity	0	-	9,889	-	0.00	100.00	0.00	0.00	9,889	-	9,889		
Builders Temp	9	-	-	3,172	0.80	0.00	0.00	0.00	2,537	-	2,537		
BT-kWh		2,168	-	-	0.00	0.00	0.00	8.10	-	176	176		
Group 1 (Standard)													
Fixed	563	-	3,081,000	-	0.00	3.00	0.00	0.00	92,430	-	92,430		
Anytime		2,067,079	-	-	0.00	0.00	0.00	5.70	-	117,824	117,824		
Controlled		859,985	-	-	0.00	0.00	0.00	3.30	-	28,380	28,380		
Nightrate		55,702	-	-	0.00	0.00	0.00	2.80	-	1,560	1,560		
DG		36,893	-	-	0.00	0.00	0.00	0.50	-	184	184		
Group 1P (Peak/Off-Peak)													
Fixed	3,771	-	20,618,999	-	0.00	3.00	0.00	0.00	618,570	-	618,570		
Peak		6,418,759	-	-	0.00	0.00	0.00	6.30	-	404,382	404,382		
Off Peak		4,648,067	-	-	0.00	0.00	0.00	4.80	-	223,107	223,107		
Controlled		5,755,285	-	-	0.00	0.00	0.00	3.30	-	189,924	189,924		
Nightrate		372,773	-	-	0.00	0.00	0.00	2.80	-	10,438	10,438		
Default		2,766,706	-	-	0.00	0.00	0.00	5.70	-	157,702	157,702		
DG		246,902	-	-	0.00	0.00	0.00	0.50	-	1,235	1,235		
Group 2 (Standard)													
Fixed	874	-	7,008,991	-	0.00	7.10	0.00	0.00	497,638	-	497,638		
Anytime		8,846,749	-	-	0.00	0.00	0.00	3.00	-	265,402	265,402		
Controlled		1,334,740	-	-	0.00	0.00	0.00	0.60	-	8,008	8,008		
Nightrate		144,849	-	-	0.00	0.00	0.00	0.20	-	290	290		
DG		67,348	-	-	0.00	0.00	0.00	0.50	-	337	337		
Group 2P (Peak/Off-Peak)													
Fixed	3,980	-	31,929,850	-	0.00	7.10	0.00	0.00	2,267,019	-	2,267,019		
Peak		18,700,062	-	-	0.00	0.00	0.00	3.30	-	617,102	617,102		
Off Peak		13,541,424	-	-	0.00	0.00	0.00	2.40	-	324,994	324,994		
Controlled		6,080,481	-	-	0.00	0.00	0.00	0.60	-	36,483	36,483		
Nightrate		659,865	-	-	0.00	0.00	0.00	0.20	-	1,320	1,320		
Default		8,060,372	-	-	0.00	0.00	0.00	3.00	-	241,811	241,811		
DG		306,809	-	-	0.00	0.00	0.00	0.50	-	1,534	1,534		
Group 2R (Remote - Fringed Hill)													
Fixed	4	-	21,900	-		10.60			2,321	-	2,321		
Anytime		73,197	-	-				3.00	-	2,196	2,196		
Time of Use													
Metered Installation Charge	88	-	-	31,769	1.45	0.00	0.00	0.00	46,065	-	46,065		
Energy		32,304,076	-	-	0.00	0.00	0.00	1.00	-	323,041	323,041		
Winter Demand		-	3,675,952	-	0.00	13.50	0.00	0.00	496,253	-	496,253		
Capacity Supply (Sum of kVA)		-	10,197,728	-	0.00	6.00	0.00	0.00	611,864	-	611,864		
Power Factor (kVAr)		-	2,979	-	0.00	0.00	6.50	0.00	19,366	-	19,366		
DG		600	-	-	0.00	0.00	0.00	0.50	-	3	3		
TOU Sealord													
Fixed	1	13,576,842	-	-	0.00	0.00	380,000.00	0.00	380,000	-	380,000		
Power Factor (kVAr)		-	-	-	0.00	0.00	6.50	0.00	-	-	-		
					0.00	0.00	0.00	0.50					
Direct Connection													
Energy		9,274,986	-	-	0.00	0.00	0.00	0.20	-	18,550	18,550		
Installation	2	-	-	732	1.45	0.00	0.00	0.00	1,061	-	1,061		
Winter Demand		-	626,615	-	0.00	10.80	0.00	0.00	67,674	-	67,674		
Capacity Supplied		-	1,244,400	-	0.00	4.00	0.00	0.00	49,776	-	49,776		
Power Factor (kVAr)		-	-	-	0.00	0.00	6.50	0.00	-	-	-		
Transpower Cold Storage		-	1	-	0.00	0.00	45,199.19	0.00	45,199	-	45,199		
Transpower NMDHB		-	1	-	0.00	0.00	86,202.01	0.00	86,202	-	86,202		
DG		-	-	-	0.00	0.00	0.00	0.50	-	-	-		
Σ II, 2024 @, 2024	9,330	136,668,683							5,378,248	2,975,982	8,354,230		
									64%	36%			

15. Future Pricing Roadmap Table – Progress Summary

Nelson Electricity has introduced a form of future pricing as of 1 April 2023. The prices are introduced after significant research, analysis and consultation with stakeholders.

The following table demonstrates the significant progress made in 2022 to finally be in a position to introduce the new future pricing options.

Focus is now on ensuring the implementation runs smoothly and then to monitor the performance of the pricing options to assess whether the retailer and consumer response is in alignment with expectations.

Consideration is now being given to the merits of introducing a separate Electric Vehicle charging pricing option as described in Section 9.

Future Pricing Roadmap Checklist EDB :

Nelson Electricity Limited

Roadmap Stages	Activities	Resource requirements												Progress since 2022	
		2022		2023		2024		2025							
		Q1	Q2	Q3	Q4	H1	H2								
1. Initiate pricing reform															
Problem Identification & Discovery	Justification and early modelling	X												NEL	Completed
Define overall objectives for reform	Set overall goals including target dates or date ranges	X												NEL / ENA / Shareholders	Completed
Develop strategy to deliver reform	Develop ideas on how to go ahead (including long list of future pricing options if available)	X												NEL / ENA / Shareholders	Completed
Communicate	Prepare and publish future pricing roadmap, include reasoning and why it's important	X												NEL	Completed
Identify challenges	eg, resourcing implications, billing systems, EEP4 file formats, AMI penetration and technology, accessing data	X												NEL - New Billing System	Completed
Consult retailers	Socialise ideas & plans with retailers		X											NEL / ENA	Completed
Establish high level plan	Gain commitment to reform, agree plan, allocate resources		X											NEL	Completed
Gather basic data for analytics	What do we need to know to progress reform? (eg. AMI penetration? Survey customers?)		X											NEL / ENA / Shareholders	Completed
Define pathway	Prepare final strategic pricing plan (including target dates)		X											NEL / ENA / Shareholders	Completed
Alignment across EDBs	Compare plan with other EDB's, form coalitions		X											NEL / ENA / Shareholders	Completed

2. Plan changes in more detail

Develop detailed plans, including:	Identify issues/prepare detailed pricing reform plans	X												NEL / ENA / Shareholders	Completed
- customer interactions	Establish research program (retailer + end-user)	X												NEL / ENA / Shareholders	Completed
- pricing trials to test ideas	Conduct in-market testing, examine impact on customer groups			X										NEL / ENA / Shareholders	Completed
- data analysis to assess customer impacts	Narrow down preferred options and test market impacts			X										NEL / ENA / Shareholders	Completed
- implementation and transition arrangements	Identify what will drive success			X										NEL / ENA / Shareholders	Completed
- feedback loops and issues resolution	Develop processes to account for stakeholder views and review against target dates. Participate in ENA			X										NEL / ENA / Shareholders	Completed
- communication	Educate customers and retailers about change			X										NEL / ENA / Shareholders	Retailers educated, Ongoing customer education
- regulatory compliance	Check plan meets regulatory expectations			X										NEL / ENA / Shareholders	Completed

3. Manage roll out of new pricing options

Develop transition strategies	Incentivise and manage take-up over time for retailers and customers													NEL / ENA / Shareholders	Completed
Adopt risk management approach	Identify and manage risks to markets, customers, EDBs (eg political and financial risks)													NEL / ENA / Shareholders	Completed
Implement New Pricing	Introduce the new pricing options													NEL	Completed
Review progress and make adjustments	Actively consider progress towards outcomes over time													NEL	Ongoing
Ongoing customer interactions	Monitor customer responses and manage as required													NEL	Ongoing

16. Loss Factors to Apply for the Period 1 April 2023 – 31 March 2024

Loss Factors will remain unchanged for the year. An assessment was undertaken in December 2022 which has shown that both technical and non-technical losses remain unchanged in the range of 3.2% - 3.7%.

Loss Code	Description	Loss Factor Consumption	Loss Factor Generation
L0	Group 0 Unmetered and Builders Temporary Supply	1.044	1.019
L1	Group 1 Residential (Low Fixed Charge Option)	1.044	1.019
L2	Group 2 Residential and Business	1.044	1.019
L3	Group 3 Large Commercial - Supplied from 400V Network	1.033	1.022
L4	Group 4 Large Commercial - Direct 400V feed from Transformer	1.033	1.022
L5	Group 5 Large Commercial - Dedicated Transformer 400V Metering	1.033	1.022
L6	Group 6 Large Commercial - Dedicated Transformer 11kV Metering	1.027	1.017

17. Compliance with Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004

Nelson Electricity Domestic Line Charge Comparison												
to comply with Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004												
Prices as at 1 April 2023												
				Anytime and Controlled 15 (2) (b) (i)		Anytime and Night 15 (2) (b) (ii)		Anytime		Anytime and Controlled and Night		
Load Group 1				No of ICP's	Type of Charge	Line Charge	Total	Total	Total	Total	Total	Total
Residential Low Fixed Charge (15kVA)				563								
1-FIXED	Fixed		cents/kVA/day	3.000	365 days	\$ 164.25	365 days	\$ 164.25	365 days	\$ 164.25	365 days	\$ 164.25
1-24HR	Anytime		cents/kWh	5.700	4800 kWh	\$ 273.60	6000 kWh	\$ 342.00	8000 kWh	\$ 456.00	5120 kWh	\$ 291.84
1-WATER	Controlled (Hot Water)		cents/kWh	3.300	3200 kWh	\$ 105.60					2240 kWh	\$ 73.92
1-NIGHT	Night Rate (11pm-7am)		cents/kWh	2.800			2000 kWh	\$ 56.00			640 kWh	\$ 17.92
							\$ 543.45	\$ 562.25	\$ 620.25			
Load Group 2 (from 15kVA to 150kVA)						Line Charge	Total	Total	Total	Total	Total	Total
Residential and Business				874								
2-FIXED	Fixed		cents/kVA/day	7.100	365 days	\$ 388.73	365 days	\$ 388.73	365 days	\$ 388.73	365 days	\$ 388.73
2-24HR	Anytime		cents/kWh	3.000	4800 kWh	\$ 444.00	6000 kWh	\$ 180.00	8000 kWh	\$ 240.00	5120 kWh	\$ 53.60
2-WATER	Controlled (Hot Water)		cents/kWh	0.600	3200 kWh	\$ 19.20					2240 kWh	\$ 13.44
2-NIGHT	Night Rate (11pm-7am)		cents/kWh	0.200			2000 kWh	\$ 4.00			640 kWh	\$ 12.80
							\$ 551.93	\$ 572.73	\$ 628.73			
				Peak/Off-Peak and Controlled 15 (2) (b) (i)		Peak/Off-Peak and Night 15 (2) (b) (ii)		Peak/Off-Peak		Peak/Off-Peak and Controlled and Night		
Load Group 1P				No of ICP's	Type of Charge	Line Charge	Total	Total	Total	Total	Total	Total
Residential Low Fixed Charge (15kVA)				3771								
1P-FIXED	Fixed		cents/kVA/day	3.000	365 days	\$ 164.25	365 days	\$ 164.25	365 days	\$ 164.25	365 days	\$ 164.25
1P-PEAK			cents/kWh	6.300	2784 kWh	\$ 175.39	3480 kWh	\$ 219.24	4640 kWh	\$ 292.32	2970 kWh	\$ 187.08
1P-OFFP			cents/kWh	4.800	2016 kWh	\$ 96.77	2520 kWh	\$ 120.96	3360 kWh	\$ 161.28	2150 kWh	\$ 103.22
1P-WATER	Controlled (Hot Water)		cents/kWh	3.300	3200 kWh	\$ 105.60					2240 kWh	\$ 73.92
1P-NIGHT	Night Rate (11pm-7am)		cents/kWh	2.800			2000 kWh	\$ 56.00			640 kWh	\$ 17.92
							\$ 542.01	\$ 560.45	\$ 617.85			
Load Group 2P (from 15kVA to 150kVA)						Line Charge	Total	Total	Total	Total	Total	Total
Residential and Business				3980								
2P-FIXED	Fixed		cents/kVA/day	7.100	365 days	\$ 388.73	365 days	\$ 388.73	365 days	\$ 388.73	365 days	\$ 388.73
2P-PEAK			cents/kWh	3.300	2784 kWh	\$ 91.87	3480 kWh	\$ 114.84	4640 kWh	\$ 153.12	2970 kWh	\$ 98.00
2P-OFFP			cents/kWh	2.400	2016 kWh	\$ 48.38	2520 kWh	\$ 60.48	3360 kWh	\$ 80.64	2150 kWh	\$ 51.61
2P-WATER	Controlled (Hot Water)		cents/kWh	0.600	3200 kWh	\$ 19.20					2240 kWh	\$ 13.44
2P-NIGHT	Night Rate (11pm-7am)		cents/kWh	0.200			2000 kWh	\$ 4.00			640 kWh	\$ 12.80
							\$ 548.18	\$ 568.05	\$ 622.49			
<p>Load Group 1 is for domestic households with connection capacity of 15kVA only (Low Fixed Tariff Option)</p> <p>Load Group 2 is available to all connections with capacity from 15kVA to 150kVA.</p> <p>Load Group 1 & 2 All current domestic households have an assessed connection capacity of 15kVA.</p> <p>Anytime, Controlled and Night assessment ratios based on average consumption of all ICP's with the three meters - Uncontrolled 64%, Controlled 28% and Night meters 8%.</p> <p>Conclusion</p> <p>Low Fixed Charge Option complies</p> <p>In all tariff configurations the General Tariff Option is higher in cost at the 8,000kWh level compared to Low Fixed Charge Option.</p>												

18. Methodology for Passing-on Settlement Residual Rebates

In November 2022, the Electricity Authority published a decision to amend the Code to require distributors to pass through settlement residual rebates (otherwise known as *losses and constraints excess* payments) to their customers. For the purposes of this Section 18, the definition of a customer is any Electricity Retailer trading on the Nelson Electricity network and any consumers with a Direct Connection Contract with Nelson Electricity.

The newly amended Code states the purpose of the requirement to pass-on settlement residue is to allocate settlement residue to customers in proportion to the transmission charges paid by those customers in respect of each connection location.

Distributors must allocate these residues on a monthly basis to customers that pay lines charges directly. Distributors must develop a methodology for allocating settlement residue to its customers that gives effect to the purpose of the Code amendment.

Accordingly, Nelson Electricity's methodology for passing-on monthly settlement residues received from Transpower for any trading period on or after 1 April 2023 is described below.

Settlement residual for a given connection location will be allocated to customers in proportion to the transmission charges paid by each customer to Nelson Electricity at that connection location.

A customer's transmission charges at a connection location will be calculated by multiplying the transmission prices published on Nelson Electricity's regulated price schedule by the equivalent billing quantities used by that customer at the connection location.

For the avoidance of doubt, billing quantities refer to the initial quantities used by Nelson Electricity to invoice the customer for the month and connection location in question.

The settlement residual received by Nelson Electricity for a given location will be allocated to customers in proportion to their contribution to the total transmission charge received from all customers at that connection location.

The formula below summarises the methodology to be used:

$$\begin{aligned} & \textit{Monthly settlement residual payment} \\ &= \textit{Monthly settlement residual} \times \left(\frac{\textit{Monthly transmission charge paid}_x}{\sum_x \textit{Monthly transmission charge paid}} \right) \end{aligned}$$

Where:

x = customer

Monthly settlement residual = Sum of monthly settlement residual payment from Transpower to Nelson Electricity and Network Tasman for connection location y

Monthly transmission charge paid_x = Transmission charge paid by customer x to Nelson Electricity

To avoid unnecessary complexity, payments will be based on initial billing quantities and will not be subject to adjustments.

Payments to customers will be made monthly.