Northpower

Pricing Methodology

1 April 2019 – 31 March 2020

1 Introduction

Northpower owns and operates the electricity distribution network covering the Whangarei and Kaipara regions, delivering electricity to more than 59,000 homes and businesses.

We recover the cost of owning and operating the network through a combination of standard (i.e. published) and non-standard prices for electricity lines services, and capital contributions for new connections. This document describes our methodology for setting our electricity lines prices.

2 Regulatory Context

2.1 Commerce Act

The Commerce Commission (“Commission”) regulates markets where competition is limited, including electricity distribution services, under the Commerce Act 1986 (“the Act”). Under the Act, an electricity distribution business (“EDB”) can be subject to information disclosure regulation, or both information disclosure and price-quality regulation.

Price-quality Regulation

Price-quality regulation is the process whereby the Commission sets the Maximum Allowance Revenue that an EDB may receive from distribution prices. As Northpower meets the definition of an exempt consumer owned EDB (because it is owned by consumers via a consumer trust, trustees are elected, over 90% of consumers benefit from distributions, and there are less than 150,000 ICPs), it is not subject to price-quality regulation.

Information Disclosure Regulation

Information disclosure regulation is the process whereby EDBs are required to publish information about their performance. The purpose of this regulation is to ensure that information is available to interested persons to assess whether the purpose of Part 4 of the Act is being met. The requirements are set out in the Electricity Distribution Information Disclosure Determination 2012 (including subsequent amendments) (“EDIDD”).

This document contains the information required to be disclosed in accordance with clauses 2.4.1 to 2.4.5 of the EDIDD.

2.2 Electricity Authority

We have developed our prices with reference to the Electricity Authority’s Pricing Principles (“Pricing Principles”). The purpose of the Pricing Principles is to ensure prices are based on a well-defined, clearly explained, and economically rational methodology. While the Pricing Principles are voluntary, the Disclosure Determination requires each EDB to either demonstrate consistency with the Pricing Principles or explain the reasons for any inconsistency.

Appendix 3 sets out the Pricing Principles and comments on the extent to which our Pricing Methodology is consistent with them.

2.3 Low Fixed Charge Regulations

We are subject to the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 ("Low Fixed Charge Regulations"). These regulations require us to offer residential consumers a price option at their primary place of residence with a fixed price of no more than 15c per day (excluding GST) and where the sum of the annual fixed and volume charges on that price option is no greater than any other residential price option for consumers using up to 8,000kWh per annum.

2.4 Electricity Code

We have developed our policies and procedures for installation and connection of distributed generation in accordance with the requirements of Part 6 (Connection of Distributed Generation) of the Electricity Industry Participation Code 2010 ("the Code").

3 Pricing Strategy

Our current pricing strategy is to transition all network pricing to be more cost reflective and responsive to the evolving market and the changing ways that consumers are using electricity. While this strategy is consistent with prior years, our execution of it has evolved and developed as demonstrated through the implementation of a residential Time of Use trial plan and the re-starting of re-balancing fixed and variable tariffs for General users this year.

Electricity networks are like roads in that they can become congested at peak times of the day. Cost reflective pricing can use price signals to demonstrate when there is capacity in our network (through lower prices), and higher prices signal times when the network is more congested. Consuming more electricity at peak times may mean we might need to incur cost to increase the capacity of our network in the future.

Emerging technology such as electric vehicles, solar panels, and batteries are changing how we consume, generate, and manage our electricity. We think it is important that pricing evolves to encourage efficient use of the network to minimise the cost of capacity increases, reduce prices for consumers in the long term and to ensure fair outcomes for all consumers on our network.

This strategy is expected to primarily impact on the Mass Market consumer group, and will broadly result in fixed prices increasing, variable prices decreasing, and differentiated pricing being available based on the time of day. We are not planning any changes to the method used to calculate the total amount of cost recouped from Mass Market consumers.

There are no changes planned to the Very Large Industrial or ND9 consumer groups as a result of this strategy.

3.1 Time of Use

As part of our journey to adopt cost reflective pricing, we have introduced a new 'Time of Use' price category (DM6) effective from 1 April 2019. This price category has higher prices during peak times of the day when the network is more congested, and lower rates during off peak times when there is plenty of capacity in the network. This indicates to consumers that consuming electricity off peak may save us money compared to consuming it at peak times, and shares this benefit with consumers who consume off peak.

In selecting Time of Use we considered a number of pricing options, including Customer Peak Demand, Network Peak Demand, Installed Capacity, and Nominated Capacity. We assessed these options against a number of criteria, including their ability to:

- Manage peak loads
- Improve utilisation of network assets
- Signal the best time to charge EV's
- Ensure all consumers contribute fairly to fixed and peak costs
- Reduce incremental cost to consume electricity
- Reduce undesirable cross subsidies
- Give consumers the ability to manage their bill (where Retailers pass through transparently)
- Be simple for consumers to understand
- Manage our revenue risk

This price category is intended to be used as a trial, and we have implemented eligibility criteria including a cap on the total number of ICPs and limiting the plan to Residential consumers. We plan to test the impact on consumption behaviour, billing processes, and gain insights and feedback from consumers and retailers. If the trial is successful, it may lead to a full roll out across Residential and General consumers.

3.2 Rebalance fixed and variable prices to achieve cost reflectivity

The majority of our costs are fixed in nature, meaning that they do not vary based on how much electricity our consumers use. This reflects the physical nature of our network, which is primarily made up of power poles, power lines, transformers, and substations. Investments to extend the network, replace assets, or create more capacity are made with a long term view of usually 40 years plus.

We are changing our pricing over time to better reflect the fixed cost nature of our business and to incentivise consumers to shift usage to times where there is spare capacity in the network. This has a number of benefits, including sharing the cost of the network more fairly across those who access the network, reducing the incremental cost to consume electricity, and reducing revenue risk.

As part of this, we have this year increased the daily price for key General price categories, and reduced the associated per kWh prices. Based on forecast volumes this change is revenue neutral. We expect further changes of this nature in coming years, within the constraints of the Low Fixed Charge Regulations which impose limits upon daily charges for some Residential consumers and therefore prevents achieving cost reflective outcomes for this group.

3.3 Roadmap

We have prepared and published a roadmap outlining our process to implement cost reflective pricing, and update it with our progress every 6 months. It is available on our website. We envisage full transition to Time of Use for residential consumers by 1 April 2021.

4 Changes to Pricing Methodology in 2019-2020

Distribution Charge Discount

We have introduced a distribution charge discount. Northpower will provide a discount for the benefit of Northpower connected consumers totalling an estimated $10.2m. This will be a discount on Northpower's distribution charges, and the amount which each consumer receives for each eligible ICP will be determined by the consumption notified to Northpower by the electricity retailers for the 12-month period to 30 September 2019 in two bands as follows:

- Eligible ICPs with consumption exceeding 2,000kWh will receive a single discount of $192
- Eligible ICPs with consumption between 1kWh and 2,000kWh will receive a single discount of $55

To qualify as an eligible ICP, an ICP must be supplied from the Northpower electricity network with a registry status of "active" (connected) on 1 November 2019, be a current customer of an electricity retailer on that date, and the net consumption advised by the electricity retailers to Northpower for the 12-month period to 30 September 2019 for the ICP must be 1kWh or greater.

Discounts will be applied via a credit on the electricity bill from the current electricity retailer during November 2019 or December 2019.

5 Target Revenue

We are targeting to recover $72.0m through prices for the year ending 31 March 2020, which covers the following components. These costs are forecast to be incurred to operate and maintain the electricity network.

Type	Component	$m
Distribution	Operating Expenditure	25.2
	Depreciation	10.0
	Regulatory Tax Allowance	3.9
	Revaluations	(5.3)
	Other Regulated Income	(0.5)
	Return on Investment	18.4
Pass through	Transmission	20.0
	Rates	0.1
	Levies	0.2
Total		**72.0**

The target revenue is flat compared to the prior year.

6 Consumer Groups

We have categorised connections to our network into three groups, in order to allocate the target revenue to these groups as part of the price setting process. The groups have been developed based on their utilisation of the network and the nature of the service that they receive.

Consumer Group	Description
VLI	Very Large Industrial ("VLI") consumers have significant Northpower assets dedicated to their site, and are supplied at either 33kV or 11kV.
ND9	ND9 consumers have significant, relatively consistent loads (e.g. supermarkets, sawmills, quarries, large pumping stations, etc.) and often have dedicated on-site distribution transformers exceeding 150kVA.

Mass Market	Mass Market includes all other sites, including homes, small to medium businesses, farms, pumps, etc supplied from our LV network.

Customers are allocated to the above groups based on their method of connection to the network (i.e. dedicated feeders / significant Northpower assets are allocated to VLI) and their load profile (i.e. significant peak or large flat load allocated to ND9) with all remaining consumers allocated to Mass Market. The allocations are made in conjunction with consumer or retailer requests to balance consumer and network outcomes.

7 Allocation of Target Revenue to Consumer Groups

We use our Cost of Service model ("CoS model") to allocate the costs of owning and operating the distribution network to the consumer groups described in the previous section, to determine how much of the target revenue we intend to recover from each consumer group. The allocators reflect how the different consumer groups drive the cost components.

7.1 Transmission

Transmission is made up of Transpower's charges for access to the national grid, and Avoided Cost of Transmission ("ACOT"). ACOT is paid to generators who inject electricity directly into the Northpower network, and through doing so reduce the charges that we would otherwise pay to Transpower.

Transpower's charges consist of two costs, 'interconnection' and 'connection'. Interconnection represents our contribution to the National Grid, and connection is the charges for assets located at the Grid Exit Point through which we connect to the National Grid.

Interconnection

Our contribution to the National Grid is charged by Transpower based on our share of the total load in the Upper North Island during the 100 half hour periods with the highest load for the prior 12-month period. We calculate the load of the different consumer groups during the same half hour periods to allocate the Transpower interconnection cost.

We also pay ACOT to generators who inject into the Northpower network during the 100 highest peaks, calculated as the amount that we would have otherwise paid to Transpower. ACOT expenses are allocated to the consumer groups using the same methodology as Interconnection, and are included in the table below.

Consumer Group	Contribution to RCPD (kW)	%	Cost ($m)
VLI	48,040	30%	5.3
ND9	12,729	8%	1.4
Mass Market	97,692	62%	10.7
Total	**158,461**	**100%**	**17.3**

To calculate the ND9 contribution to RCPD, we assume that their load is 60% of their Network Peak Period Demand (their peak demand between 0700 – 1000 and 1700 – 2130 between May to September) based on historical analysis. Their demand has historically been lower at the time of the UNI peaks because of their load profile, reflecting their industries and the times of the day that they use electricity.

Connection

Transpower also charges us for our share of the costs for the grid exit points ("GXPs") that we use, based on the value of the assets and our usage of those assets. These are allocated to the consumer groups based on their contribution to the total peak demand at the GXPs, averaged over the 12 highest half hour periods at each GXP for the Capacity Measurement Period (for 2019/2020 pricing, the period from September 2017 to August 2018). ND9 is again assessed at 60% based on historical analysis.

Consumer Group	to GXP peak (kW) Contribution	%	Cost ($m)
VLI	63,963	37%	1.6
ND9	12,729	7%	0.1
Mass Market	97,148	56%	0.9
Total	**173,840**	**100%**	**2.7**

We connect to Transpower's national grid at three different GXPs, Bream Bay, Maungatapere, and Maungaturoto. The costs of each GXP have been attributed separately to each consumer group, and then added together. As such, the percentage of a consumer's groups contribution to GXP peak may vary from their percentage contribution to cost at a total level.

7.2 Operating Expenditure

Asset Costs

Asset costs are the costs to maintain and repair network assets, and primarily relate to materials and labour. These costs have further been allocated into operating costs (consisting of preventative maintenance, rates, electricity, rent, etc.) and fault related costs.

Operational costs relate to running and maintaining the core assets in our network, and therefore the costs are allocated based on the proportion of the asset value that each consumer group uses. Where an individual asset can be identified as being dedicated to a consumer group, it is wholly allocated to that consumer group. Likewise, where an asset can be identified as not being used by a consumer group, it is allocated between the consumer groups who do use it.

Asset	Allocator	VLI	ND9	Mass Market
Sub-transmission lines	Peak demand	16.0%	11.6%	72.4%
Sub-transmission cables	Peak demand	33.0%	11.6%	55.4%
Zone substations	Peak demand	15.0%	11.6%	73.4%
HV + LV lines	Length	0.0%	2.0%	98.0%
HV + LV cables	Length	0.0%	2.0%	98.0%

Distribution substations and transformers	HV Length	0.0%	2.0%	98.0%
Distribution switchgear	HV Length	0.0%	2.0%	98.0%
Other network assets	ICPs	0.0%	0.0%	100.0%
Non-network assets	Assessment	5.0%	3.0%	92.0%
Weighted Total	**Asset Value**	**3.8%**	**3.8%**	**92.4%**

Fault related costs are generally driven by issues connected with lines, and as such are allocated based on line length.

Asset	Allocator	VLI	ND9	Mass Market
Sub transmission	Length	12.5%	10.2%	77.4%
High Voltage	Length	0.0%	2.7%	97.3%
Low Voltage	Length	0.0%	0.0%	100.0%
Weighted Total	**Length**	**0.6%**	**2.2%**	**97.2%**

Non Asset Costs

Non Asset costs are the overhead costs to operate and maintain the network. They include the engineers who monitor the performance of the network, design extensions and upgrades, and plan for the future. It also includes the customer services teams, operations teams who monitor the network 24/7 and manage outages, health and safety, and billing functions. We allocate these costs based on an estimate of the proportion of total resources that each consumer group utilises.

Return on Investment, Depreciation, Regulatory Tax Allowance, and Revaluations

These costs are where we recover the depreciation on the assets which make up our network, the cost of tax, and a return on our investment. This component is important because it allows us to replace assets as they reach the end of their lives, and to invest in new assets as the network expands, new technology, and improve the performance and reliability of the network.

These costs relate to the underlying network assets, and are therefore allocated to the consumer groups based on the assets that each consumer group uses as described above.

7.3 Total Target Revenue allocated to each Consumer Group

Using the allocators described above, we allocate the $72.0m target revenue to each of the consumer groups. The target amount that we intend to recover from each group is outlined below:

	Component	VLI $m	ND9 $m	Mass Market $m	Total $m
Distribution	Operating Expenditure	1.1	1.7	22.4	25.2
	Depreciation	0.4	0.4	9.2	10.0
	Regulatory Tax Allowance	0.1	0.2	3.6	3.9
	Revaluations	(0.2)	(0.2)	(4.9)	(5.3)
	Other Regulated Income	0.0	0.0	(0.5)	(0.5)
	Return on Investment	0.7	0.7	16.9	18.4
Pass through	Transmission	6.9	1.5	11.6	20.0
	Rates	0.0	0.0	0.1	0.1
	Levies	0.1	0.0	0.1	0.2
Total		**9.1**	**4.3**	**58.6**	**72.0**

8 Price Setting Process

The following sections explain how we set our prices to recover the Target Revenue allocated to each consumer group. It explains what types of prices are used, and how the prices are set.

Types of Prices

The types of prices used across our price categories are described below. Only some of these components apply to each price category.

Price Component	Units	Description
Daily price	$/day	Daily price is applied to the number of days each ICP is connected to our network.
Monthly price	$/month	Monthly price is applied to the number of months each ICP is connected to our network.
Volume	$/kWh	Volume price applied to the electricity distributed to each ICP. The rate may vary depending on the price category, for example uncontrolled (available 24 hours a day), controlled 18 (available 18 hours a day), or controlled 22 (available 22 hours a day).
Anytime maximum demand	$/kVA/month	Anytime maximum demand is the highest half-hour demand at any time each year. It is initially charged based on the prior year, and then adjusted during the year based on actuals, including monthly wash-ups.
Network Peak Period demand	$/kVA/month	Network Peak Period Demand is the consumer’s peak demand between 0700 – 1000 and 1700-2130 from May to September, which reflects the peak periods on our network and generally coincides with the UNI regional peaks. It is calculated as the average of the 6 highest half hour periods. It is initially charged

		based on the prior year, and then adjusted during the year based on actuals, including monthly wash-ups.
Excess Reactive Power	$/excess kVAr/month	Where the power factor falls below 0.95 lagging for the highest half hourly demand in a month, the excess kVAr is charged.

8.1 Mass Market

We have a number of Mass Market price categories to comply with regulations and meet the needs of different groups of consumers.

Consumer Group Subset	Price Category Code	Description
Residential	DM1	Principal place of residence
	DM3	Non-principal residence
	DM4	Inclusive (Obsolete)
	DM6	TOU Principal Residence
General	ND1	Up to 70kVA (100A or less)
	ND2	Greater than 70kVA (CT metering)
	ND5	Irrigation and pumps
	ND6	Unmetered 24 Hour
	ND12	Builders Temporary Supply
Streetlights	H	Daily Price
	26-1	Demand band 1
	26-2	Demand band 2
	26-3	Demand band 3
	26-4	Demand band 4
	26-5	Demand band 5

Our process to set prices is to forecast the expected volumes for each price category and component, and adjust the prices to achieve our Mass Market revenue target of $58.6m. Our pricing strategy informs our approach to making these changes. For 2019-2020 there has been a reallocation between the Distribution Price and the Transmission Price but no change in total Delivery Price from the previous year for most price components.

We have increased the daily price for some General price categories (ND1, ND5, and ND6) from $1.00 to $1.20 and reduced the variable prices accordingly, to better reflect the fixed nature of our cost base. This change is forecast to be revenue neutral to Northpower. For more detail on the prices of individual price components compared to the prior year please see our pricing schedule here.

We have also introduced the TOU Principal Residence price category, which is for our Time of Use pricing trial. The prices for this price category have been set with reference to our existing prices for residential controlled and uncontrolled loads.

The Low Fixed Charge Regulations require us to offer residential consumers a price option at their primary place of residence with a fixed price of no more than 15c per day (excluding GST) and where the sum of the annual fixed and volume charges on that price option is no greater than any other residential price option for consumers using up to 8,000kWh per annum. Our DM1 Principal Place of Residence price category complies with these regulations.

8.2 ND9

We offer large commercial and industrial consumers the option of our ND9 Demand-based price category. This category charges consumers based on their peak usage rather than their consumption, which is more reflective of the network costs that they drive.

Our process to set prices is to forecast the expected volumes for each price category and component, and adjust the price to achieve our ND9 revenue target of $4.3m. Our pricing strategy informs our approach to making these changes. For 2019-2020 there has been a reallocation between the Distribution Price and the Transmission Price but no change in total Delivery Price for the ND9 price components. For more detail on the prices of individual price components compared to the prior year please see our pricing schedule here.

We note there is one consumer in the ND9 consumer group for which Anytime Demand is assessed in a non-standard manner. This site has an atypical load profile and so rather than creating a separate price category, it is assessed using a modified criterion whereby the Anytime Maximum demand is agreed in advance on the basis of the expected daytime peak loads in the coming year, and any peak demands after midnight are ignored.

8.3 Very Large Industrial

We offer non-standard pricing to very large industrial consumers who would like us to own and operate assets of significant value which are dedicated to their supply. We currently have 6 consumers in this consumer group, of whom 4 are billed directly on non-standard contracts and 2 via a retailer. Consumers in this group can choose if they want to be on a non-standard contract or billed via retailer.

The pricing is asset based to ensure Northpower recovers the costs of the dedicated and shared assets, an appropriate return on investment, and the associated operating and maintenance costs. Transmission costs are passed through in a transparent manner.

The revenue target for these consumers is $9.1m for 2019-2020. We forecast that revenue from these consumers will be $8.9m, primarily due to contractual limitations preventing target revenue being achieved. This contract is of a long term nature and was agreed prior to the implementation of the current regulatory regime.

8.4 Distributed Generation

We do not currently charge distributed generators to use our network to convey electricity to their customers. In the event that costs are incurred to connect a generator to the network, we will look to recover those costs.

We pay ACOT of $1.4m to two large scale generators under Part 6 of the Electricity Industry Participation Code. This involves assessing the generator's average output at the time of the 100 highest UNI peaks, to calculate the Transpower interconnection cost saved due to the generator injecting into our network at the time of those peaks.

We do not pay ACOT to owners of small scale generators below 10kWh, as most small scale generation is solar and therefore the generation is unlikely to coincide with the UNI 100 highest peaks and reduce the Transpower transmission cost as a result.

9 Responsibilities to Very Large Industrial consumers

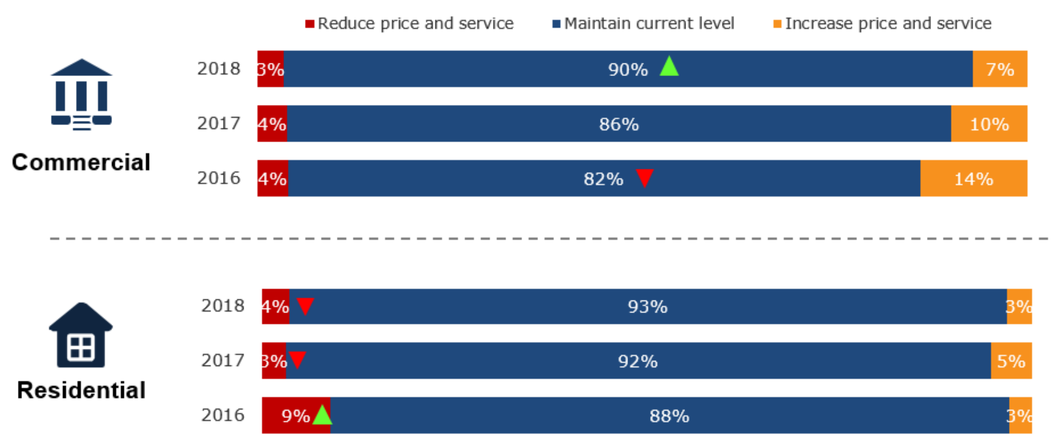
Our obligations and responsibilities to VLI consumers are broadly the same as other consumers. The key difference is that VLI consumers are able to input into their supply configuration, and as such they sometimes opt to duplicate assets to increase security of supply. For example, some VLI sites elect to have two incoming feeders, each capable of supplying the entire load for the site, to ensure they have a backup if one feeder fails.

The non-standard pricing offered to our VLI consumers reflects the assets which they use, and as such their contribution towards target revenue covers the additional cost of the duplication of assets to improve security of supply.

10 Consultation

We consult with a range of stakeholders including consumers, retailers, and the Northpower Electric Power Trust on behalf of our consumer owners, on a range of issues including their views on pricing, quality, and the desirable level of trade-off between these two factors. For example, the below question is part of an annual survey of consumers, the most recent conducted in 2018. The majority of consumers are satisfied with the current levels of service. We factor these views into our expenditure planning, which flow into our target revenue and ultimately prices.

Preferred Level of Service(1)(2)



NOTES:
1. Sample: 2016 Total n=400, Commercial n=100, Residential n=300; 2017 Total n=400, Commercial n=300, Residential n=100; ; 2018 Total n=400, Commercial n=300, Residential n=100
2. CP3. Northpower's level of service is based on reliability of supply, supply quality such as avoiding surges and spikes, and response times to faults. Changes in service levels might require changes in price. If you had to choose which one of the following best describes what you prefer?

▲ *Significantly higher than...*
▼ *Significantly lower than...*

We consulted with retailers on the changes made to 2019-2020 pricing, including the introduction of the DM6 TOU Principal Place price category.

Appendix 1: Proportion of Target Revenue by Price Component

Price Component	Price Component Code	%
Mass Market		
General daily price	A, P	5.53%
Large Commercial daily price	B	0.34%
Principal place of residence daily price	C, X	3.44%
Non-principal residence daily price	W	1.50%
Builders Temporary Supply daily price	T	0.31%
Residential Uncontrolled	2	38.04%
All-inclusive (Obsolete)	71	0.11%
Non-principal Residence Uncontrolled	3	0.83%
General Uncontrolled	33, 43	13.16%
Large Commercial Uncontrolled	32	5.01%
Metered lighting	19	0.00%
Unmetered lighting	24	0.04%
Builders Temporary Supply Uncontrolled	53	0.10%
Controlled 18 hour	06, 46	4.95%
Controlled 22 hour	05, 55	2.74%
Night only	07, 47	0.04%
Controlled day	11	0.13%
Controlled night	12	0.05%
Daily price per unmetered installation	G	0.12%
Unmetered Uncontrolled	25	0.03%
Daily price per unmetered light fitting	H	0.92%
Half-hour metered volume-based daily price	J	0.12%
Half-hour metered volume-based	31	3.05%
TOU Principal Residence	R	0.08%
Peak	61	0.33%
Shoulder	62	0.31%
Off-peak	63	0.10%
ND9		
Large Commercial and Industrial - Demand-based prices	9	5.95%
Very Large Industrial		
Non-standard pricing	IND	12.65%
Total		**100%**

Appendix 2: Glossary

Term	Definition
AMD	Anytime Maximum Demand. The highest half-hour demand, usually in kVA, during a one year period.
Avoided Cost of Transmission ("ACOT")	A reduction in the transmission costs payable by distributors to Transpower (usually in the context of embedded generation).
Code	Electricity Industry Participation Code 2010 and subsequent amendments.
Commission	Commerce Commission
Consumer	A person or an entity whose electricity installation is connected to the electricity network.
Consumer Group	A broad category of electricity consumers.
Controlled	An option where consumers elect to have part of their electricity supply subject to interruption at Northpower's discretion. The most common example is control of electrically heated hot water.
Demand	Electricity load, measured in either kW or kVA, usually averaged over a half-hour period.
Distributor (EDB)	An entity other than Transpower which owns an electricity network other than an embedded network. Often denoted as an Electricity Distribution Business (EDB).
Distributed generation (DG)	An electricity generator connected directly to an electricity distribution network (rather than to the transmission grid). Also called Embedded Generation.
EDIDD	Electricity Distribution Information Disclosure Determination 2012 published by the Commerce Commission as Decision NZCC 22 dated 1 October 2012, as subsequently amended.
Electricity Industry Act (EIA)	Electricity Industry Act 2010.
Half-hour metered	An ICP with metering that records electricity consumption in half-hour intervals.
ICP	Installation Control Point. An individual connection to an electricity distribution network.
kVA	Kilovolt-amp. Measure of total apparent power.
kVAr	Reactive power.
kW	Kilowatt. Measure of true power.
kWh	Kilowatt-hour. Rate of energy flow.
Low Fixed Charge Regulations	Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Non-principal place of residence	A residential premise that is not the principal place of the consumer in the context of clause 3 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Non-standard contract	A contract that is not a standard contract in terms of the EDIDD 2012. (Refer to definition of Standard contract below).
Point of Connection (PoC)	The connection between the transmission grid and a distribution network. Also called a Grid Exit Point (GXP).

Power factor	kW/kVA
Pricing Principles	The distribution pricing principles published by the former Electricity Commission in 2010, adopted by the Electricity Authority, and amended from time to time.
Principal Place of Residence	In the context of clause 3 of the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004.
Regional Coincident Peak Demand (RCPD)	The average demand at the times of the hundred highest half-hour regional demands.
Residential Consumer	A consumer at a residential ICP which satisfies the definition of "domestic premises" in Section 5 of the Electricity Industry Act 2010.
SOLEC	Separation of Line and Energy Charges – a process undertaken in the 1990's prior to the introduction of competition in the energy sector.
Standard contract	EDIDD 2012 defines a standard contract as one where the price for electricity line services is determined solely by reference to a publicly disclosed schedule of prescribed terms and conditions, or a contract which covers at least five persons, none of which is a related party to the EDB or each other.
TPM	Transmission Pricing Methodology – the methodology defined in accordance with Part F (subpart 4) of the Code by which transmission prices are allocated to participants with connections to the national electricity grid.
Transmission grid	The national electricity grid owned and operated by Transpower.
Upper North Island (UNI)	The area of the North Island north of Huntly.

Appendix 3: Consistency with Electricity Authority Pricing Principles

Pricing Principle	**Consistency of Northpower pricing methodology**
(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), except where subsidies arise from compliance with legislation and/or other regulations and/or the Government Policy Statement; ii. having regard, to the extent practicable, to the level of available service capacity; and iii. signaling, to the extent practicable, the impact of additional usage on future investment costs.	**Mass Market** Northpower's costs are largely fixed, driven by the physical footprint of the network and long term nature of investment decisions. Variable costs are largely limited to the Transpower transmission charges. By contrast, Mass Market prices are predominantly based on connection days and kWh consumed. As such, there are subsidies inherent in our pricing structure, such as between peak and off peak users, low and high consumers of electricity from the grid, those that live in dense vs non-dense parts of the network, and those that are close to or further away from the GXP. Subsidies between low and high consumers of electricity are being addressed through reweighting fixed and variable charges, within the limitations of the Low Fixed Charge regulations. We are making these changes over time to mitigate and manage the impact on consumers. Subsidies between peak and off peak users, as well as signalling the available service capacity, and the impact of additional usage on future investment costs, will be addressed through the implementation of cost reflective pricing. We are implementing a trial of Time of Use pricing from 1 April 2019 to test consumer and retailer responses and supporting processes. We note that these changes are being phased over a period of time and including significant stakeholder engagement to observe the pricing principle that development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders. We do not plan to address subsidies between dense and non-dense parts of the network, and those that are closer to or further from the GXP. Consistent with pricing principle (e), we consider that the costs of developing and administering separate pricing structures for urban and rural consumers would be economically inefficient and impose unnecessary transaction costs on consumers and retailers. In addition, as a consumer owned organisation we do not believe this is an outcome sought by our consumer owners. **ND9** ND9 consumers' prices are based on their peak consumption, and as such they reflect the service capacity available to them and signal the cost of additional usage. There may be some low level cross subsidies within the group such as distance from GXP.

	Very Large Industrial VLI consumers' prices are based on the assets they use and as such we consider these charges to be subsidy free, reflective of the service capacity they have available to them, and signal the cost of additional usage through transmission pricing and the cost of installing additional assets. We note there are instances where we are constrained by contractual arrangements.
(b) Where prices based on 'efficient' incremental costs would under-recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers' demand responsiveness, to the extent practicable.	This principle refers to the economic concept of "Ramsey Pricing", where prices are inversely adjusted according to their elasticity of demand. That is, prices are higher for those customers who are less likely to change demand as a result of price changes. This is considered economically efficient as consumers that demand a service the most, pay the most. Setting prices based on incremental costs would almost certainly under-recover target revenues, as the majority of our costs are both fixed and sunk so do not vary with the next unit of consumption. **Mass Market and ND9** Implementation of this principle would require us to charge higher prices to consumers who are less likely to reduce their demand if their price was higher. The contra to this is identifying consumers who would use more if the price was reduced, and reducing their price. This is economically efficient because it maximises utilisation of the asset and therefore reduces the average cost for all users. This principle is challenging to implement, as we can't discriminate by having different pricing for different consumers within the same group, and we need to comply with the pricing principle (e) that pricing should not impose unnecessary transaction costs through being unnecessarily complex. Where practicable, we are rebalancing our fixed and variable charges to reflect the cost structure of our business. This has the effect of reducing the incremental cost to consume, and reducing the price to those who are likely to consume more as a result of a price change. It inversely increases the comparative price for those who are unlikely to change their demand as a result of a price change. Our Time of Use trial plan will further embed this principle. Consumers who consume electricity during peak periods and are unwilling to change their demand (i.e. by reducing or shifting peak load) will pay the most, and the price will be reduced for those who might increase their consumption (provided they do so where there is network capacity). **Very Large Industrial** The pricing for this consumer group is based on the assets that they utilise, and the incremental transmission costs incurred. As such this pricing structure has regard to consumer's demand responsiveness because if they change their consumption, their asset usage will change and their pricing will also change in reflection. Pricing will increase for consumers willing to pay for a higher level of service, in terms of either or both of security and capacity, and vice versa.

(c) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to: i. discourage uneconomic bypass; ii. allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services; and iii. where network economics warrant, and to the extent practicable, encourage investment in transmission distribution alternatives (e.g. distributed generation or demand response) and technology innovation.	**Mass Market and ND9** Uneconomic bypass occurs when the charges from Northpower drive consumers to seek alternate options, but the alternate option bears cost for the consumer but does not reduce costs by the same amount for Northpower. Northpower's prices currently feature relatively low daily prices and high marginal costs to consume, which provide an incentive for consumers to install distributed generation. This allows them to reduce their consumption over the network, whilst still retaining the same connection and ability to draw from the network when required. The consumer incurs the cost to install the distributed generation, but Northpower's costs are not reduced because they still need to operate the same physical assets to connect the consumer's house to the network, still need to operate a network over the same physical area, and because the distributed generation is generally solar and doesn't generate at times of peak demand, still has the same levels of congestion during and transmission costs driven by peak periods. The outcome is uneconomic because the total cost to consumers has increased to deliver effectively the same service. We are currently rebalancing fixed and variable prices over a period of time to address this principle, but note that the Low Fixed Charge Regulations prevent rebalancing for consumers who are eligible for and opt into a plan compliant with these regulations. Consumers in these groups are not currently able to negotiate on their pricing, reflecting the practical limitations due to the number of consumers in these groups. We do however survey consumers to understand their views on price, service levels, and the trade-off between these factors. This is factored into our price setting processes. Current pricing encourages investment in transmission distribution alternatives, but past the point where economics warrant due to the uneconomic bypass outcome outlined above. **Very Large Industrial** VLI pricing is asset based and includes a transparent pass through of transmission pricing, thereby discouraging uneconomic bypass. Some of the customers in this group could choose to connect directly to Transpower, but our transparency has ensured it is economic for them to connect via the Northpower network and clearly identifies the Northpower costs and the value received by consumers for this cost. These consumers are able to negotiate contracts that reflect the economic value of services, and to make price/quality trade-offs by varying the services they receive. For example, they may wish to purchase feeder duplication which will increase costs but also reduce the risk and length of outages. The transparent nature of pricing also encourages to the extent economical, investment in transmission alternatives such as distributed generation or demand response.
(d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders.	We manage price stability and certainty for stakeholders by changing pricing structures gradually over a number of years, including trialling changes before rolling out widely, conducting test and learn campaigns, and engaging with stakeholders to communicate changes. We have regard to the impact on stakeholders by consulting widely including with consumers and retailers on material changes to pricing structures, are cognisant of the impact of pricing changes on consumers, and that the design of pricing structures enables consumers to respond to the price signal to

	manage their costs. As such, we seek to strike a balance between pure economic efficiency, and structures which are economic to implement and operate, and are simple enough for consumers to understand and respond to on a daily basis.
(e) Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers.	We are cognisant that there is a trade-off between implementing structures which are economically efficient, and the complexity and consequentially the transaction cost to do so. We make and implement these assessments as part of developing prices. For example, we have implemented a Time of Use price category effective from 1 April 2019. An option in designing these prices was to have different prices for different seasons, months, days or the week, or half hour, but we judged that the transaction costs would outweigh economic efficiency gains from doing so, neither was such complexity supported by retailers. We are continually simplifying our pricing categories and working to remove grandfathered categories, and also work closely with neighbouring Top Energy to align future price categories to reduce transaction costs for consumers and retailers.

Schedule 17: Certification for Year-beginning Disclosures

(Distribution Pricing Methodology for the year commencing 1 April 2019)

Clause 2.9.1

We, Mark Desmond Trigg and Phillip Gordon Hutchings, being Directors of Northpower Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Northpower Limited prepared for the purposes of clauses 2.4.1 to 2.4.5 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.

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PGG.

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[Signatures of 2 directors]

Date 28/2/2019