Pricing Methodology

For delivery prices effective 1 April 2022

Pursuant to the requirements of clause 2.4 of the Electricity Information Disclosure Determination 2012 (consolidated 2021)

Alpine ENERGY

Contents

1. About Alpine Energy Limited

We (Alpine Energy Limited) have over 34,079[1] interconnection points (ICPs) throughout South Canterbury. Our area of supply covers over 10,000 km² and is located on the East Coast of the South Island, between the Rangitata and Waitaki Rivers, and inland to Mount Cook on the main divide. We have seven grid exit points (GXPs) and 24 substations on our network. Almost 84% of our ICPs are on smart meters. Figure 1 below shows a map of our network.

Figure 1: Map of Alpine Energy's network

We are 100% owned by the South Canterbury community through our shareholders:

[1] Not all the ICP's on the network is currently connected. Refer to Table 1 for details on connected ICP's.

- Timaru District Holdings Limited (47.5%), a wholly owned subsidiary of Timaru District Council
- Line Trust South Canterbury (40%)
- Waimate District Council (7.54%)
- Mackenzie District Council (4.96%)

1.1 We want to help you understand how we set prices

This pricing methodology outlines our approach to setting electricity distribution delivery charges to apply from 1 April 2022.

Delivery charge describes the total price we charge to transport electricity from the national grid to consumer's homes and businesses.

Delivery prices include:

- Alpine Energy's distribution charges
- Pass-through and recoverable cost charges, including Transpower's transmission charges
- Any wash-up balances from previous years

The purpose of this document is to show how our electricity pricing methodology (or approach) sets delivery prices to recover the costs of supplying distribution services, from the appropriate consumers, most efficiently and fairly.

- This section describes the role of pricing, and the network, consumer, and regulatory characteristics we consider when developing prices
- Section 2 describes our current pricing approach, and our plans to evolve our pricing approach as consumer preferences and technology change how our network is used
- Section 3 describes changes we made to prices for 2022/2023
- Section 4 describes how we set the standard and non-standard prices, and distributed generation pricing
- Section 5 describes the consumer groups paying delivery charges
- Section 6 describes how we calculate and allocate costs across consumer groups
- Section 7 describes how we assess the consumer impact of price changes
- Appendix A describes how the pricing approach aligns with the Pricing Principles published by the Electricity Authority
- Appendix B describes how we comply with clauses 2.2.1 to 2.4.5 of the Electricity Information Disclosure Determination 2012 (consolidated December 2021)

1.2 Network characteristics

Our distribution network is in good condition. Two-thirds of our capital expenditure over the next nine years to 2031 is targeted for the replacement and renewal of existing infrastructure. Network development capital expenditure accounts for a third of the investment in our network. This investment is specifically targeted for consumer connections, reliability safety and environment projects, and network augmentation.

Electricity is delivered to our network via seven grid exit points (GXPs) with Transpower and one embedded generator at the Opuha dam.

For the year ending March 2022, the estimated electricity volume carried is 841GWh (2021 actual: 836 GWh) with a maximum network demand of 158 MW (2021 actual: 144 MW). By 2025/26 the volume carried is expected to increase to 1,399 GWh (prior year forecast: GWh 921 GWh) and maximum network demand is expected to increase to 237 MW (prior year forecast: 156 MW).

Energy consumed varies from year to year depending on wet or dry irrigation seasons, and severe or mild winters. Growth in network demand has been about 2.49% per year over the last 18 years. Growth is expected to remain consistent with this trend. More detail on the network characteristics for the seven supply areas is outlined in table 1 below.

Measure	ABY [2]	BPD	STU	TKA	TMK	TIM	TWZ	Total
ICPs	1,694	626	3,374	997	6,983	18,446	1,689	33,809
O/H line (km)	590	197	551	254	920	942	61	3,515
UG line (km)	30	22	47	74	148	479	48	855
Main Substation	2	2	1	4	5	3	1	18
Peak demand (MW)	5	15	14	5	60	67	4	169
Energy consumption (GWh)	24	52	68	23	294	364	16	841

Table 1: Network characteristics for the seven GXPs as per 2021 – 2031 asset management plan

[2] Albury (ABY) energy is net of energy injected from the Opuha generation

The main drivers influencing electricity demand in our area relates to weather and economic activity. Economic activity in our area of operation strongly influences the configuration of our network. Over the last decade, we have been through a major economic growth phase in South Canterbury, mainly due to dairy conversions, irrigation schemes and dairy processing.

More detail of the impacts on network investment and operation impacts of the major demand drivers, is in the 2021 Asset management plan and updates available at https://www.alpineenergy.co.nz/corporate/reports-and-publications/asset-management-plan.

Table 2 below summarises the main load type and forecast capacity adequacy for each GXP supply area.

Location (GXP)	Load type and forecast capacity adequacy	Pricing Implications
Albury	Small townships, sheep & beef farming, some dairying. Adequate capacity to meet a small growing demand.	No material growth with adequate capacity, no proposed pricing changes.
Bells Pond	Dairy processing at Oceania Dairy Limited factory and on-farm dairying irrigation (Waihao Down irrigation scheme). Adequate capacity to meet the growing demand.	Upgrades negotiated with the dairy factory directly, investigating irrigation pricing options to manage peak loads.
Studholme	Sheep and beef farming, some dairying, Fonterra Studholme dairy factory. Major replacements and upgrades will be required if there is an increase in Fonterra demand requirements.	No material growth with adequate capacity, investigating irrigation pricing options to manage peak loads.
Tekapo Twizel	Twizel and Tekapo townships experiencing significant growth; dairy conversions and irrigation developments slowing due to land use/discharge requirements. Major upgrades expected in next 5 years.	Growth-related costs being managed, no proposed pricing changes.

Location (GXP)	Load type and forecast capacity adequacy	Pricing Implications
Temuka	Temuka and Geraldine townships, dairying irrigation, and Fonterra Clandeboye dairy factory. Adequate capacity to meet a small growing demand. Major replacements and upgrades will be required if there is an increase in Fonterra demand requirements.	GXP constrained, upgrades and pricing negotiated with the dairy factory, investigating irrigation pricing options to manage peak loads.
Timaru	Timaru – residential, commercial, and light industrial. Upgrading supply to Washdyke industrial area. Adequate capacity to meet the growing demand.	No material growth with adequate capacity, no proposed pricing changes.

Table 2: Load type, forecast capacity adequacy, and pricing implications for main GXP supply areas

The network is experiencing congestion in some areas, mostly isolated, due to distributed generation exporting into the network. The list of export congestion areas is available on our website at https://www.alpineenergy.co.nz/customers/generating-electricity/export-congestion-areas.

If export congestion causes operational issues, we may interrupt the connection of any distributed generation to the distribution network or curtail either the operation or output of distributed generation, or both, and may temporarily disconnect the distributed generation from the distribution network.

1.3 Consumer characteristics

With our network covering an area between the Rangitata and Waitaki rivers, from the coast to Mt Cook, we supply the communities of Timaru, Temuka, Waimate, and MacKenzie basin and surrounding areas. 16 electricity retailers were trading as 23 retail brands, supplying consumers on the Alpine network.

About 42% of connections are served by one retailer. Except for six large consumers that we directly invoice for electricity line charges, our line charges are passed to consumers along with transmission charges and energy supply charges by the electricity retailers. Table 3 shows the number of consumers (ICPs) in each supply area.

Location	ICP Count	%
Timaru	16,397	48.1%
Waimate	3,768	11.1%
Temuka	3,532	10.4%
Geraldine	3,109	9.1%
Twizel	1,736	5.1%
Pleasant Point	1,281	3.8%
Fairlie	1,220	3.6%
Lake Tekapo	880	2.6%
Pareora	483	1.4%
Orari	307	0.9%
Glenavy	274	0.8%
St Andrews	243	0.7%
Winchester	226	0.7%
Cave	216	0.6%
Albury	183	0.5%
Makikihi	117	0.3%
Mount Cook	107	0.3%
Total	**34,079**	**100.0%**

Table 3: Total ICP count and percentage of total by region

The Timaru GXP constitutes almost half of the Alpine network connection points and consumption which is primarily residential, commercial, and small industrial customers.

Winter peak loading occurs mainly at Timaru and Tekapo GXPs, although other urban areas, like Fairlie and Geraldine, also have significant demand for load during the winter months. Winter load demand may rise due to more regulation around air quality and particulate matter, restricting the use of fires for heating and placing greater demand on the network to service other forms of heating, such as heat pumps and other conventional electric heating.

The increase in tourism and subdivisions in Tekapo and Twizel is now also a driver we use in our forecasting models.

The peak demand in the dairy industry occurs in spring and extends into summer. Load requirements are for processing, on-farm milking, heating, and cooling as well as irrigation. Reliability of supply is therefore very important in this industry. As a result, most shutdowns for maintenance or network upgrade activities have to be planned for the dairy 'off' season.

At an individual farm level, operations are intensifying due to increasing cooling and holding standards. There is greater use of irrigation and new technologies. There is an increasing requirement for higher reliability of supply and better quality of supply than was previously the case. This growth has consumed most of our spare network capacity, with major new builds in areas where no infrastructure existed.

There has been significant growth in dairy farming and processing, bringing an increased demand from irrigation. Irrigation load is the main cause of summer peak loading at all the GXPs except Timaru, Tekapo, and Twizel although the increase in irrigation is tempered by local environmental restrictions on water use, land intensification, and nitrogen discharge limits.

Our large industrial and commercial consumers are mainly located in Timaru and more specifically around the port, Redruth and Washdyke areas.

1.4 Regulatory characteristics

Our pricing approach is influenced by a range of regulatory requirements, including obligations imposed by the Commerce Commission and Electricity Authority, and through the Electricity (Low Fixed Charge Tariff for Domestic Consumers) Regulations 2004 and the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2021 (LFC Regulations).

The main implications are:

- We are required to set prices to recover no more than the revenue allowed by the Commerce Commission's *Electricity Distribution Services Default Price-Quality Determination 2020, [2020] NZCC 3,* 20 May 2020 (DPP Determination). Sections 5-7 of this document describe how we set prices to recover no more than the allowed revenue
- We are required to disclose information about our pricing approach and prices by the Commerce Commission's Electricity Distribution Information Disclosure Determination 2012 – (consolidating all amendments as of 9 December 2021) (ID Determination). Appendix B describes how we meet the disclosure requirement
- We are expected to set efficient and cost-reflective prices consistent with the Electricity Authority's Distribution Pricing Principles published in June 2019. Appendix A describes how our pricing approach aligns with the Pricing Principles

- We are required to set prices for distributed generators connecting to and using our network according to Part 6 of the Electricity Industry Participation Code 2010 (the Code), relating to the pricing of distributed generation. Section 4 describes how we do this
- We are required to offer domestic consumers a low fixed charge tariff option by the LFC Regulations. The Electricity Authority monitors and enforces the regulations. Section 5.4 describes how we comply with the LFC Regulations

2. Current pricing and future pricing plans

We set delivery prices using a retail delivery approach, also referred to as an installation control point (ICP) pricing methodology. The network service is priced at the consumer's metering point based on the electricity consumption at that point.

The price of our network service is set taking account of the network, consumer, and regulatory characteristics relevant to our network. Our goal is to set the price of our network service to reflect the cost of delivering that service to each consumer group. This means, to the extent practicable, using fixed charges to recover fixed costs and variable charges to recover variable costs.

2.1 Current pricing

Our network service prices for most connections have a three-part structure, with a fixed daily charge component, and two variable components with a volume-based charge for daytime usage (7 am to 11 pm) and a volume-based charge for night-time usage (11 pm to 7 am).

Network service prices for connections with time-of-use (TOU) metering, and capacity greater than 15kVA have a four-part structure, with an additional fixed-like kw/day capacity charge component.[3]

An overview of the 2022/2023 price structure and price components for each mass market consumer group is provided in table 4 below. More detail on each consumer group is provided in section 6.

[3] The daily capacity charge component is fixed-like because the quantity (capacity of the connection) is fixed for the year, meaning the amount paid by the consumer does not vary with day-to-day consumption or any other factor but may vary year to year if the consumer chooses to vary their connection capacity.

PRICING SCHEDULE EFFECTIVE FROM 1 APRIL 2022		DELIVERY CHARGES				NUMBER OF CONSUMERS
		FIXED per day	VARIABLE DAY per kWh	VARIABLE NIGHT per kWh	DEMAND per KW/day	as at 31/03/2023[4]
LOWHCA	Low User (controlled) high-cost area	$0.3000	$0.1018	$0.0716	$0.0000	2,228
LOWLCA	Low User (controlled) low-cost area	$0.3000	$0.0962	$0.0659	$0.0000	11,001
LOWUHCA	Low User (uncontrolled) high-cost area	$0.3000	$0.1258	$0.0956	$0.0000	13
LOWULCA	Low User (uncontrolled) low-cost area	$0.3000	$0.1193	$0.0891	$0.0000	45
015HCA	Single Phase (controlled) high-cost area	$1.5050	$0.0529	$0.0227	$0.0000	5,800
015LCA	Single Phase (controlled) low-cost area	$1.3654	$0.0529	$0.0227	$0.0000	11,189
015UHCA	Single Phase (uncontrolled) high-cost area	$2.0972	$0.0529	$0.0227	$0.0000	32
015ULCA	Single Phase (uncontrolled) low-cost area	$1.9367	$0.0529	$0.0227	$0.0000	36
360HCA	Three Phase (controlled) high-cost area	$6.1807	$0.0529	$0.0227	$0.0000	525
360LCA	Three Phase (controlled) low-cost area	$4.4840	$0.0529	$0.0227	$0.0000	743
360UHCA	Three Phase (uncontrolled) high-cost area	$6.6626	$0.0529	$0.0227	$0.0000	14
360ULCA	Three Phase (uncontrolled) low-cost area	$5.0756	$0.0529	$0.0227	$0.0000	13
ASSHCA	Assessed demand high-cost area	$2.0611	$0.0529	$0.0227	$0.1488	1,252
ASSLCA	Assessed demand low-cost area	$1.4259	$0.0529	$0.0227	$0.0967	403
TOU400HCA	Time-of-Use metering at 400 V high-cost area	$1.4657	$0.0165	$0.0071	$0.4178	35
TOU400LCA	Time-of-Use metering at 400 V low-cost area	$1.1694	$0.0230	$0.0099	$0.2732	95
TOU11HCA	Time-of-Use metering at 11 kV high-cost area	$1.2215	$0.0287	$0.0123	$0.2431	6
TOU11LCA	Time-of-Use metering at 11 kV low-cost area	$1.1845	$0.0228	$0.0098	$0.3850	4

Table 4: Overview of current price structure and price components for each consumer group 2022/23

[4] Represents the forecasted number of ICPs for the year ending 31 March 2023.

2.2 Economic signals delivered by current pricing

Alpine recovers the costs of delivering electricity to consumers through prices. Prices signal the value of the network service users receive at a location and point in time.

There is a relationship between prices, cost, and value of the network service and consumers' behaviour in using the network, e.g., a fixed charge pricing signal would encourage network use at any time and level for many consumers but would discourage connection for some consumers, particularly with low levels of consumption.

There are several long-term impacts of economic signalling in pricing:

- 'All you can eat' fixed pricing on an unconstrained network may result in increased consumer consumption resulting in congestion leading to higher levels of network investment
- If consumers opt for alternative energy supplies, it could lead to consumers disconnecting or not connecting to the network. This would lead to a reduction in connections and revenue base over time
- Variable volume-based charges discourage the use of the network. It also creates uncertainty in revenue and cost recovery as consumers can reduce electricity consumption behaviours
- There could be adverse impacts where costs were increasingly borne by consumers without the ability to reduce electricity consumption

Pricing structures that reflect fixed or avoidable (variable) costs should signal the cost of the service appropriately.

Currently, the fixed daily charge and demand charge (for connections with the metering capability to identify their contribution to loading) is recovered from the relevant time-of-use consumer groups.

Alpine's pricing is designed to recover the following costs:

- Operating expenditure relating to reliability, safety, and environment, routine and corrective maintenance and inspection, and system operations and network support
- Capital related costs, including return on capital, depreciation, revaluations, and regulatory tax
- Pass-through and recoverable costs, including transmission costs

The variable volume-based day/night charges for all consumer groups are set to recover costs of:

- Operating expenditure relating to asset relocations, replacement and renewal, service interruptions and emergencies, system growth, and vegetation management

- Pass-through and recoverable costs, including transmission costs

These costs are considered variable as they vary with day-to-day use of the network and may be avoided by a change to network use.

Prices are set to reflect the economic signals for investment as follows:

- Individually billed customers' prices are based on the investment which Alpine has made to these large industrial connections and the contribution of transmission assets in use to provide these customers with electricity
- Medium-sized connections with time-of-use metering are based on their share of assets and consumption within the Low and High costs areas of network density signalling the cost to serve
- Low user customers prices are based on the LFC Regulations
- Mass market customers are based on a shared residual cost of network assets within the Low and High costs areas of network density signalling the cost to serve.

There is not currently complete alignment between fixed and avoidable costs, and fixed (and fixed-like) and variable charges. Table 5 below shows the average proportion of revenue recovered from each consumer group by fixed (daily) and fixed-like (capacity) charges and by variable (volume) charges.

Consumer Group	Revenue recovered by fixed charges (%)	Revenue recovered by variable charges %
LOWHCA	15	85
LOWLCA	15	85
LOWUHCA	12	88
LOWULCA	13	87
015HCA	40	60
015LCA	40	60
015UHCA	40	60
015ULCA	40	60
360HCA	60	40
360LCA	60	40
360UHCA	60	40
360ULCA	60	40
ASSHCA	77	23
ASSLCA	55	45
TOU400HCA	76	24
TOU400LCA	55	45
TOU11HCA	45	55
TOU11LCA	58	42

Table 5: Average proportion of revenue recovered from each consumer group by fixed & fixed-like charges and variable charges

We estimate that most of our operational costs are fixed, with a portion being avoidable depending on extreme events. Costs recovered through variable charges intend to manage consumer behaviour or future network investment.

The relationship between costs and charges can improve for most consumer groups due to the historical over-reliance on variable charges for revenue and cost recovery. The implication is that the current pricing, on average, discourages the use of the network, and particularly given our network has spare capacity in most locations and times[5]. Additionally, current prices may undermine revenue and cost recovery and may

[5] https://www.alpineenergy.co.nz/__data/assets/pdf_file/0014/17105/Alpine-Energy-AMP-2021-FINAL.pdf

contribute to adverse equitable outcomes. The correlation between prices and costs are being addressed as part of our plans to evolve our pricing.

2.3 Evolving our pricing and prices

Our desired end state is a cost-reflective model which results in delivery prices set to reflect our circumstances and the cost of delivering a safe, reliable electricity supply.

We recognise that our current pricing methodology, like most electricity distribution businesses in New Zealand, is not yet reflective of new technologies and trends (including uptake of distributed rooftop solar PV coupled with battery energy storage systems (BESS), electric vehicle charging and decarbonisation regulations). We know that our pricing methodology needs to change to be more agile and to deliver the best outcomes for all our consumer groups. The process to implement the changes required is complex and takes years to develop and implement. Revising our pricing strategy will be a key strategic focus for us over the next 12 months, during which we will, after consultation with retailers, determine a medium and long-term pricing strategy.

We will disclose the pricing strategy in our pricing methodology disclosures for 2023/2024.

3. Pricing changes for 2022/2023

We are increasing prices across most consumer groups for 2022/2023 when compared to 2021/2022. The reasons for the changes and the average impact on delivery prices are described below. Our prices reflect the price path under the DPP Determination.

Changes to price levels

We set prices to recover the allowable distribution revenue, and pass-through and recoverable costs (including transmission costs).

Alpine's forecast revenue from prices increased by 6% from $54.10 million to $57.41 million. The increase is due to the combined impact of:

- Increase in forecast net allowable revenue[6] for 2022/23 by 2% from $43.48 million to $44.37 million
- Pass-through costs increase by 8% from $0.39 million to $0.42 million, mainly due to increases in Commerce Act levies
- Recoverable costs (excluding transmission costs) increase from negative[7] $0.21 million to positive $0.22 million, mainly attributable to the movement in the incremental rolling incentive scheme (IRIS), which for 2022/2023 is forecasted to be positive $0.33 million (2021/2022 – negative $0.44 million)
- Transmission costs have an increase of 8% from $13.64 million to $14.74 million. This is predominantly due to increased interconnection charges from Transpower

Alpine's lines charge for mass-market customers will increase in 2022/2023 by an average of 0.7% compared to 2021/2022, whilst the lines charges for direct billed customers will increase by an average of 12% in 2022/2023.

The change in revenue for each consumer group, and average delivery price change from the resulting changes to price levels are described in table 6 below.

[6] Forecast net allowable revenue is determined by the Commerce Commission in Schedule 4 of the Electricity Distribution Services Default Price-Quality Path Determination 2020 (Consolidated 20 May 2020).

[7] The recoverable costs being negative implies that we will not be recovering these costs from consumers, but rather represents a decrease in lines charges.

Consumer Group	$ Change in revenue 2021/2022 to 2022/2023	% Change in revenue 2021/2022 to 2022/2023	Average delivery price change ($)
LOWHCA	463	2.9%	0.15
LOWLCA	1,520	12.8%	0.15
LOWUHCA	6	0.0%	0.15
LOWULCA	27	0.1%	0.15
015HCA	268	10.0%	0.07
015LCA	(109)	(16.9%)	(0.07)
015UHCA	6	0.1%	0.01
015ULCA	-	0.1%	0.01
360HCA	33	3.0%	0.06
360LCA	(128)	(3.5%)	(0.01)
360UHCA	6	0.1%	0.01
360ULCA	(1)	(0.1%)	(0.04)
ASSHCA	740	23.1%	0.09
ASSLCA	(172)	(5.3%)	(0.76)
TOU400HCA	27	2.6%	0.75
TOU400LCA	42	7.0%	8.14
TOU11HCA	38	2.2%	0.37
TOU11LCA	(47)	(1.3%)	(4.27)

Table 6: Change in forecast revenue and average delivery prices between 2021/22 and 2022/23

We considered the consumer impact of the delivery price changes. Our approach to assessing and managing consumer impact of price changes is described in section 7.

Changes to the price structure

We have not changed any price structures for 2022/23.

4. How prices are set

Prices for consumers using our networks to consume electricity are set in two ways:

- Standard pricing for residential and most commercial consumers is supplied according to the price categories in the standard price schedule
- Non-standard direct-billed customers

We also set prices for distributed generators, including payments to distributed generators providing network support services. When setting prices, we consider the opportunity to share the value of deferring network investment.

We do this by introducing a discount to variable charges (to signal a benefit of changing behaviour) or by directly contracting with a party supplying a network support service.

4.1 Standard pricing

We set standard prices using the following process:

We **determine consumer groups**. Section 5 gives more detail.

- Assign consumers (connections) to groups for allocating total costs

We calculate and allocate costs to consumer groups. Section 6 gives more detail.

- Confirm the forecast net allowable revenue we can recover for the year. Forecast net allowable revenue is determined by the Commerce Commission to reflect efficient costs of supplying distribution services
- Calculate forecast pass-through and recoverable costs for the year. The forecasts are made based on actual costs for the prior year adjusted by an average historic growth rate
- Allocate costs to each consumer group, to as closely as possible, align the benefit of access and use of the distribution service and cost of supplying the distribution service
- Determine price structures for each consumer group based on the relevant cost allocations and complying with the relevant legal requirements

We assess consumer impacts of pricing variations. Section 7 gives more detail.

- Check the impact on consumers of pricing variations and adjust pricing as needed

4.2 Non-standard pricing for direct billed customers

For the period ending 31 March 2022, we had six direct billed customers with 12 ICPs connected to our network at present. We are not expecting any new direct billed connections before 31 March 2023.

The decision to place a new connection onto a direct billed contract is made on a case-by-case basis. When making this decision we consider the:

- Cost of the build
- Number of new assets required
- Extent of the existing network that will be used by the new connection
- Capital contribution paid
- Ongoing costs that will be recovered through delivery prices
- Required security of supply

The following methodology is used for calculating prices for directly billed customers[8]. We enter into long-term contracts with direct billed customers. This gives Alpine the ability to negotiate outcomes that are consistent with market-like arrangements.

4.3 Calculation and recovery of the cost of new assets

The capital contribution paid for new assets can reduce the ongoing delivery prices that the customer will pay.

If a capital contribution equals the total value of the new assets allocated to the customer, the customer may not pay the cost of capital or depreciation charges for these new assets. They will, however, pay for ongoing maintenance charges for these assets through their delivery prices.

[8] For some direct billed customers, the pricing methodology will differ to the one described above due prior long-term contracts in place.

If the capital contributions do not cover the full cost of the value of new assets used by the customer, then the remaining value of the asset (after capital contributions) will be used to calculate the cost of capital and depreciation charges. Depreciation charges are calculated on a remaining life basis, with the age of the asset taken from the Commerce Commission's *Optimised Deprival Value Handbook (2004)*.

When calculating the return on capital charges we apply the Commerce Commission's weighted average cost of capital for the industry, and the closing regulatory value of the new asset (adjusted for inflation) from the previous year, using a mid-year cash flow.

4.4 Capital contributions based on the perceived risk of the investment

We calculate the value of the capital contribution on the perceived risk of the investment. The perceived risk is calculated using a risk algorithm which we fill out then pass to the customer for comment.

The risk algorithm calculates a percentage score which translates to the percentage of the total investment cost that should be paid as a capital contribution. For example, if the risk algorithm calculates risk to be 0.75 then we would require a capital contribution of 75% of the total investment cost.

4.5 Maintenance charges payable

Maintenance charges effectively bank the cost of maintaining assets. That is, while new assets will have little maintenance after the first year of service, the maintenance charge will cover future replacement costs. However, the maintenance charge will not cover future costs to upgrade capacity.

4.6 Recovering the cost of existing network assets

If the customer also requires the use of existing network assets, then the cost of capital charges, depreciation, and maintenance charges apply for these assets.

4.7 Allocators for recovering costs

The portion that a customer will pay for the use of existing network assets will depend on the most relevant cost driver for that asset. For lines and cables, costs are apportioned to the customer based on the customer's the line/cable length to the total line/cable lengths in the network.

For substations, transformers, protection, and switchgear, costs are apportioned to the asset using the total demand or capacity[9] of all users of

[9] The use of demand or capacity will depend on the type of asset that the cost relates to.

the asset including the direct billed customer, to the total demand or capacity of the asset type across the network. Costs are then apportioned to the customer according to the customer's demand or capacity to the total demand/capacity relevant to the asset.

4.8 Recovering the future costs of grid upgrades in capacity

Please note that our costs are fixed in the short term so that a drop in consumption will have little or no impact on our short term (annual) costs. However, a decrease in consumption over the long term can delay or prevent upgrades in network capacity due to the under-recovery of our required revenue.

4.9 Recovery of transmission costs

Transmission costs are passed through to the customer according to the customer's demand to the total demand of all users of the GXP to which the consumer is connected. The exception is the interconnection charge which is charged out to the consumer at the Transpower rate per kW of consumer demand during the regional coincident peak demand (RCPD).

Difference between direct bill and standard agreement security standards

Customers on a direct billed contract can expect one planned outage each year and an unplanned outage of two hours every five years, plus a momentary unplanned outage every two years[10]. These service standards are not available to consumers on the shared distribution charges model. For both direct billed customers and consumers on the shared network, we give a minimum of four working days' notice before a planned shutdown occurs. We do not guarantee supply or offer compensation if supply is lost to any connection.

Capital contributions

In addition to the delivery charge revenue that we receive from our consumers, we also receive capital contributions from any consumer that requires to be connected to our network or needs upgrades to their existing connection. Costs of upgrades to an existing connection can be shared where there are network benefits to the upgrade.

Where the upgrade is for the sole benefit of the consumer, the consumer must pay in entirety for that upgrade.

Capital contributions cover the cost of the work carried out, after rebates. If 100% of capital costs are paid by capital contributions, there should be no remaining costs to be recovered through delivery prices except ongoing operational costs (i.e., Opex). Without a capital contribution, these extensions or upgrades would be uneconomic under standard delivery prices.

[10] Some contracted service standards will differ for older contracts.

For larger builds generally over $500,000, we will calculate the risk of the investment and use this to determine the percentage of capital contributions payable. When calculating risk we invite the investor to comment on our risk score and resulting capital contributions.

A copy of our *New Connections and Extensions Policy* can be found on our website[11].

Distributed generation on our network

Our network provides the means for distributed generators of all types and sizes to convey electricity to end-users.

As at 31 January 2022 there were 526 distributed generators connected to our network:

- 502 distributed generators (less than 10kW capacity) installed at residential or commercial premises
- 24 distributed generators (more than 10 kW capacity). One of these is the Opuha hydro installation with a 9MW capacity

Fees payable by distributed generators to us are set by the Electricity Authority under the *Electricity Industry Participation Code* (the Code)[12]. Schedule 6.5 of the Code prescribes the maximum fees we can charge to distributed generators. These fees include application fees and fees for observation of testing and inspection.

Payment for distributed generation is made by retailers, and the rates can be found on the respective retailer websites.

We encourage generators of solar energy (photovoltaic cells), wind, water (hydroelectric), or fossil fuels such as diesel or natural gas that have energy surplus to their requirements to sell into the network. We do this by allowing generators to use our distribution network without incurring any network charges, other than the fees charged in accordance with the Code.

[11] https://www.alpineenergy.co.nz/customers/getting-connected/new-connections-and-extensions-policy

[12] Schedule 6.5, Electricity Industry Participation Code 2010, Part 6, Connection of distributed generation.

Information about the connection to our network and our application process for connection and operation of distributed generation by both small and large, distributed generators is available on our website[13].

5. Consumer Groups

We assign our 'standard consumers' to one of 18 consumer groups for pricing.

We supply our standard consumers under our Default Distribution agreements we have with electricity retailers. Most of the consumers on our network is standard consumers.

5.1 Assigning standard consumers into load groups

Table 7 below lists the 18 consumer groups with their defining characteristics. Consumers are assigned to a consumer group based on location, the capacity of the connection, maximum business day peak demand, and meter configuration.

Consumer group	Description
LOWHCA	Primary residence that consumes less than 9,000 kWh per annum – high-cost area
LOWLCA	Primary residence that consumes less than 9,000 kWh per annum – low-cost area
LOWUHCA	Uncontrolled Primary residence that consumes less than 9,000 kWh per annum – high-cost area
LOWULCA	Uncontrolled Primary residence that consumes less than 9,000 kWh per annum – low-cost area
015HCA	0-15kVA and up to 60 Amp fuse – high-cost area
015LCA	0-15kVA and up to 60 Amp fuse – low-cost area
015UHCA	Uncontrolled 0-15kVA and up to 60 Amp fuse – high-cost area
015ULCA	Uncontrolled 0-15kVA and up to 60 Amp fuse – low-cost area
360HCA	3 x 60 Amp fuses – high-cost area
360LCA	3 x 60 Amp fuses – low-cost area

13 https://www.alpineenergy.co.nz/customers/generating-electricity

Consumer group	Description
360UHCA	Uncontrolled 3 x 60 Amp fuses – high-cost area
360ULCA	Uncontrolled 3 x 60 Amp fuses – low-cost area
ASSHCA	Assessed demand over 15kVA – high-cost area
ASSLCA	Assessed demand over 15kVA – low-cost area
TOU400HCA	Time of use 400 volt400-volt supply – high-cost area
TOU400LCA	Time of use 400 volt400-volt supply – low-cost area
TOU11HCA	Time of use 11kV supply – high-cost area
TOU11LCA	Time of use 11kV supply – low-cost area

Table 7: Consumer groups

5.2 Location – high cost and low-cost area allocation

For standard consumers the revenue requirement is allocated to high-cost area and low-cost area, using our geographic information system (GIS). The cost areas represent the number of consumers:

- On each transformer
- Per kilometre of distribution line length

On average there are 13 times more ICPs per line km in the low-cost area compared to the high-cost area. Capital expenditure costs and operating expenditure costs to service connections in rural areas that are less populated are higher (High-Cost Areas) than servicing clustered connections in towns (Low-Cost Areas).

5.3 Allocation of consumers to consumer groups within cost areas

Consumers in the high-cost area and the low-cost area are split into the following consumer groups:

- Low fixed charge group
- Mass-market installed capacity groups:
  - 015– (0-15 kVA single phase 60 A connection)
  - 360– (45 kVA three-phase 60 A connection)
- Assessed (ASS) demand groups based on fuse size
- TOU groups for LV and 11kV connections with half-hour metering

5.4 Low fixed charge consumer group

We must comply with the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations* 2004 and the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Amendment Regulations 2021 (LFC Regulations), which state that we must offer a fixed tariff for 'domestic' consumers of no more than $0.30 per day (2021/2022: $0.15 per day). A domestic consumer is defined by the regulations as a person who purchases electricity for their 'principal place of residence' (clause 4(1)).

We fulfil low fixed charge obligations by offering the low user consumer groups that pay a daily fixed price of $0.30. We also ensure that an 'average' consumer[14] in the low consumer groups pays no more than an 'average' consumer in an alternate 015 consumer group, by adjusting the costs allocated to the low user consumer groups. This means the low user group pays less than the costs of supply, with these costs met by other consumers.

The low-user fixed charge obligations are currently being phased out with a $0.15 increase in fixed charges over a 5-year period effective 1 April 2022. This is the first year of five and accordingly, the $0.30 per day fixed charge for low-users is in place.

[14] The regulations define 'average', on the South Island, as a consumer who consumes 9,000 kWh annually.

5.5 015, 360 and assessed demand consumer groups

ICPs not in the low fixed charge consumer groups and without TOU meters[15] installed, fall into one of three consumer groups:

1. 15 kVA (015 consumer group)
2. 3 x 60 A (360 consumer group)
3. Assessed demand (ASS consumer groups).

ICPs in the 015-consumer group are single-phase and have a maximum capacity of 15 kVA (60 A), although we may also allow a 3x32 A connection on a case-by-case basis. ICPs in the 360 consumer groups have three-phase 60 A connections. ASS consumer groups have a maximum capacity per phase greater than 60 A. This can include two-phase connections. Demand charges for consumers in the ASS consumer groups are calculated on the fuse size (installed capacity) of the connection.

The mass market and assessed demand groups are grouped by installed capacity and fuse size. The resulting capacity bands broadly reflect costs of supplying the distribution network by providing a proxy for relative use of the network, including during peak demand periods. Ideally, we would have actual peak demand data.

We are working toward obtaining this data via our smart meter roll-out. Currently, this information is only available on a case-by-case basis, on request, and normalised across the ICP sample from retailers.

5.6 Time of use consumer groups

ICPs in the TOU consumer groups have TOU meters installed, which record kWh consumption every half an hour. From TOU meters we can calculate the after diversity maximum demand (ADMD), and network peak demand, which are used to allocate costs to consumer groups, and calculate demand charges.

5.7 Uncontrolled load

Uncontrolled load tariffs are charged to consumers in the LOW, 015, and 360 consumer groups whose electrical hot water heating load we are not permitted to control during periods of high demand. The uncontrolled load tariff excludes the discount offered to consumers which provides us a demand response service by allowing the ability to control the load. The controllable load is critical for us during supply emergencies, and to avoid further investment in network capacity.

The additional distribution charge of $0.0484/kWh for day and night usage in the LOWUHCA, and $0.0418/kWh for day and night usage in the

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15 Some ICP's in the assessed consumer groups may have half hour metering installed but choose to remain in the assessed group.

LOWULCA load groups is charged based on usage advised by electricity retailers. The additional variable transmission charge of $0.0245/kWh for day and night usage for sites in the LOWUHCA and LOWULCA load groups is a special charge for provision of electric water heating that cannot be controlled by us via a ripple relay and is charged based on usage advised by electricity retailers.

6. Allocating Costs Across Consumer Groups

We set prices by calculating and allocating total allowable revenue for the assessment period across each specific consumer group. The process involves:

- Confirming the total net forecast allowable revenue allowed by the Commerce Commission for the assessment period, as specified in schedule 1.4 of the DPP Determination[16]
- Forecasting the pass-through and recoverable costs
- Calculating the opening wash-up account balance
- Allocating costs to specific consumer groups
- Checking alignment between cost types and price components

6.1 Total forecast revenue

Our total forecast revenue (or referred to as target revenue) recovers annual distribution and pass through and recoverable costs, shown in table 8 below[17].

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[16] https://comcom.govt.nz/__data/assets/pdf_file/0025/216862/Electricity-distribution-services-default-price-quality-path-determination-2020-consolidated-20-May-2020-20-May-2020.pdf

[17] Please note the forecast business costs from 2020 AMP and Information Disclosures when prices are set.

Component	$ '000
Operating expenditure (OPEX)	
Service interruptions and emergencies	1,989
Vegetation management	850
Routine and corrective maintenance and inspection	3,330
Asset replacement and renewal	290
Non-network OPEX	13,924
Capital related costs	
Depreciation	15,719
Return on capital	5,338
Regulatory tax	2,926
Pass-through costs and recoverable costs	
Rates on system fixed assets	133
Commerce Act levies	86
Electricity Authority levies	186
Utilities Disputes levies	19
IRIS adjustment	329
Transpower transmission charges	13,396
New investment contract charges	1,338
System operator services charges	10
Quality incentive adjustment	(16)
Capex wash-up adjustment	(134)
Fire and emergency NZ levies	40
Opening wash-up account balance	(2,345)
Total target revenue	**57,408**

Table 8: Revenue requirement for the year ending 31 March 2023

6.2 Major cost components

Our distribution revenue requirement recovers annual regulated network costs for the period 1 April 2022 to 31 March 2023 and includes:

- Forecast net allowable revenue, which is derived from the following costs components:
    - Operating expenditure
    - Depreciation
    - Revaluations
    - Return on capital
    - Regulatory tax
- Pass-through and recoverable costs
- Opening wash-up account balance

Each cost component is discussed in more detail below.

6.3 Operating expenditure

Operating expenditure (Opex) are costs incurred through our business-as-usual operations related to the provision of electricity distribution services. The two main costs components are:

- Maintenance on network assets including related non-network overhead
- Quality of service (service interruptions and emergencies)

Forecast maintenance costs for the year ending 31 March 2023 are derived from our 10-year network Opex budget, found in schedule 11b of the 2021 to 2031 Asset Management Plan.

6.4 Depreciation

Depreciation is calculated on a straight-line basis in accordance with ID Determination using a standard life for the asset[18]. Depreciation costs for the year ending 31 March 2023 are forecast using historical depreciation on our regulatory asset base (RAB) sourced from the *Financial-model-EDB-DPP3-final determination*[19] as issued by the Commerce Commission.

[18] Standard lives for each asset group are determined by the Commerce Commission, *Handbook of Optimised Deprival Valuation of System Fixed Assets of electricity Lines Businesses*, 30 August 2004, table A.1, page 33

[19] https://comcom.govt.nz/__data/assets/excel_doc/0025/191464/Financial-model-EDB-DPP3-final-determination-27-November-2019.xlsx

6.5 Revaluations of the regulatory asset base

Our regulatory asset base (RAB) is revalued using the following formula:

- Opening RAB value – depreciation + revaluations + assets commissioned – disposals + assets lost/found + adjustment for asset allocation = closing RAB value

The change in our RAB is reflected in our return on investment.

6.6 Return on investment

Our return on investment has been calculated using the regulated weighted average cost of capital (WACC) on a forecast value for network RAB as at 31 March 2023, considering forecast commissioned assets for 2022/2023 and revaluations. A vanilla (post-tax) WACC (67th percentile) of 4.23% has been applied.

Our RAB, as at 31 March 2021 was $210.58 million. This is an increase of approximately $4.98 million when compared to the value of our RAB as at 31 March 2020.

6.7 Regulatory tax

We recover regulatory tax through our distribution charges. The forecast regulatory tax value for the period ending 31 March 2023 is $2.9 million and was sourced from the Commerce Commission forecasts for DPP3[20].

6.8 Pass through and recoverable costs

Pass through costs include:

- Rates on system fixed assets
- Commerce Act levies
- Electricity Authority levies
- Utilities Disputes levies

We forecast these costs based on the actual costs to date for 2021/2022, adjusted for a historic growth rate, as this provides the most accurate estimate of future costs.

[20] Commerce Commission website, https://comcom.govt.nz/__data/assets/excel_doc/0025/191464/Financial-model-EDB-DPP3-final-determination-27-November-2019.xlsx

Recoverable cost include:

- IRIS incentive adjustment
- Transpower transmission charges
- New investment contract charges
- System operator services charges
- Avoided transmission charges – purchased assets
- Distributed generation allowance
- Claw-back
- Catastrophic event allowance
- Extended reserves allowance
- Capex wash-up adjustment
- Quality incentive adjustment
- Transmission asset wash-up adjustment
- Reconsideration event allowance
- Quality standard variation engineers fee
- Urgent project allowance
- Fire and emergency NZ levies
- Innovation project allowance

The two largest components of the recoverable costs are the IRIS incentive adjustment and the transmission charges. The IRIS incentive adjustment is calculated in accordance with the DPP Determination[21]. Transmission charges are estimated based on the actual invoices received from Transpower. In November each year, we receive a notice of the coming year's transmission pricing from Transpower for each GXP on our network. We use this notice to calculate transmission prices for each load group.

[21] https://comcom.govt.nz/__data/assets/pdf_file/0025/216862/Electricity-distribution-services-default-price-quality-path-determination-2020-consolidated-20-May-2020-20-May-2020.pdf

In November each year, we receive a notice of the coming year's transmission pricing from Transpower for each GXP on our network. We use this notice to calculate transmission prices for each load group.

Allocating costs to specific consumer groups

We allocate the required revenue to load groups using cost allocators and rationale described in table 9 below:

Cost component	Allocator	Rationale
Operating expenditure	ADMD	Opex is related to the consumer's use of the network in terms of required capacity and utilisation (demand). Opex is allocated to load groups based on after diversity maximum demand.
	Weighted RAB	Network Opex is allocated to asset sub-categories based on the weighted average of each ODV asset category to the total regulatory assets base.
Recovery of revenue forgone from RCP1	ADMD	Impact of any over or under-recovery under the price cap is allocated to load groups based on after diversity maximum demand.
	Weighted RAB	Total cost is allocated to asset sub-categories based on the weighted average of each ODV asset category to the total regulatory assets base.
Revaluations and sundry income	NA	Revaluations are recovered through the return-on-investment component, which takes into account the revaluation of the RAB each year.
Depreciation	ADMD	Depreciation is compensation to our owners for the reduction in asset values that occur over time. Depreciation is allocated to load groups based on the load groups after diversity maximum demand.
	Weighted Depreciation	Total cost is allocated to asset sub-categories based on the weighted average of each ODV asset category to the total depreciation.

Cost component	Allocator	Rationale
Return on investment	ADMD	Our owners are compensated for investing in Alpine Energy through a return on the value of the asset base. We recover this value based on the structure of the RAB, where network assets are planned and built around providing future capacity requirements. That is, we recover the return on investment based on load group after diversity maximum demand.
Non-network costs	Pro-rata basis	Non-network costs are generally not driven by consumer demand for power. These costs are allocated evenly amongst ICPs, except for individual customers who pay an allocation of shared costs based on contractual terms.
Transmission	ADMD	Transmission charges are allocated to non-standard consumers based on the contribution to the regional coincident peak demand—new investment and connection charges and after diversity maximum demand—interconnection charges.
	RCPD	Transmission charges are allocated to standard consumers based on the groups' regional coincident demand—new investment and connection charges and after diversity maximum demand—interconnection charges.
Pass-through and recoverable costs	ICP	Allocated to standard consumer groups based on ICP count.
Opening wash-up account balance	ICP	Allocated to standard consumer groups based on ICP count.

Table 9: Cost allocators used and rationale for selection

The total target revenue allocated to each consumer group for the year ending 31 March 2023, based on the allocators described in table 8 above, is shown in table 10 below:

Consumer group	Year ending 31 March 2023 Target Revenue $'000	Year ending 31 March 2022 Target Revenue $'000	Change in Target Revenue $'000	% Change in Target Revenue
LOWHCA	1,672	1,212	463	2.9%
LOWLCA	7,350	5,830	1,520	12.8%
LOWUHCA	18	12	6	0.0%
LOWULCA	53	26	27	0.1%
015HCA	5,713	5,445	268	10.0%
015LCA	9,692	9,801	(109)	(16.9%)
015UHCA	51	45	6	0.1%
015ULCA	43	43	-	0.1%
360HCA	1,709	1,676	33	3.0%
360LCA	2,037	2,165	(128)	(3.5%)
360UHCA	68	62	6	0.1%
360ULCA	41	42	(1)	(0.1%)
ASSHCA	13,238	12,498	740	23.1%
ASSLCA	3,057	3,229	(172)	(5.3%)
TOU400HCA	1,508	1,481	27	2.6%
TOU400LCA	4,018	3,967	42	7.0%
TOU11HCA	1,274	1,236	38	2.2%
TOU11LCA	740,602	$788	(47)	(1.3%)
IND	5,126	$4,544	582	8.9%
Total	**57,408**	**$54,104**	**3,301**	**100%**

Table 10: Target revenues per load group

Table 11 below describes the allocation of the target revenue to price components, by consumer group.

Load group	Distribution		Transmission		%		Total
	Fixed $'000	Variable $'000	Fixed $'000	Variable $'000	Fixed	Variable	$'000
LOWHCA	244	1,129	-	298	14.6%	85.4%	1,672
LOWLCA	1,205	4,779	-	1,367	16.4%	83.6%	7,350
LOWUHCA	1	10	-	6	8.1%	91.9%	18
LOWULCA	5	29	-	19	9.3%	90.7%	53
015HCA	3,186	1,425	-	1,102	55.8%	44.2%	5,713
015LCA	5,576	2,320	-	1,795	57.5%	42.5%	9,692
015UHCA	18	15	7	11	49.0%	51.0%	51
015ULCA	18	10	8	7	60.1%	39.9%	43
360HCA	1,184	296	-	229	69.3%	30.7%	1,709
360LCA	1,216	463	-	358	59.7%	40.3%	2,037
360UHCA	31	19	3	15	50.3%	49.7%	68
360ULCA	21	10	3	8	56.9%	43.1%	41
ASSHCA	5,629	3,715	1,021	2,873	50.2%	49.8%	13,238
ASSLCA	1,032	886	454	685	48.6%	51.4%	3,057
TOU400HCA	825	210	349	124	77.9%	22.1%	1,508
TOU400LCA	1,482	1,479	665	392	53.4%	46.6%	4,018
TOU11HCA	393	437	204	240	46.9%	53.1%	1,274
TOU11LCA	260	139	213	128	63.9%	36.1%	741
IND	2,967	-	2,158	-	57.9%	42.1%	5,126
Total	**25,292**	**17,373**	**5,086**	**9,657**	**52.9%**	**47.1%**	**57,408**

Table 11: Proportion of target revenue collected through each price component

6.9 Allocating distribution costs

Our pricing model allocates distribution costs to consumer groups in a way that reduces cross-subsidisation between users of the network so that those that each consumer groups pays for the assets that the consumer group uses.

We do this by allocating costs based on each consumer group's demand, we do this as demand is the main cost driver of distribution costs. We allocate network costs by the consumer groups after diversity maximum demand.

6.10 Allocating pass-through and recoverable costs

When calculating consumer group prices to recover annual pass through and recoverable costs, we use forecast rates and levies from local authorities, the Commerce Commission, and the Electricity Authority.

We allocate forecast pass-through and recoverable costs to consumer groups, by multiplying the forecast annual pass through and recoverable cost by the number of ICPs in a consumer group to total ICPs on the network.

6.11 Allocating transmission costs

When calculating consumer group prices to recover annual transmission costs, we use Transpower's transmission costs effective from 1 April 2021. From the total, we remove the annual transmission revenue we expect to recover from direct billed customers, before allocating the remainder to consumer groups.

From the remaining transmission costs, we remove the revenue we expect to receive from consumers who pay extra for not giving us control of their hot water cylinder (uncontrolled consumer). We allocate connection and new investment agreement costs to consumer groups using a consumer group's after diversity maximum demand, and interconnection costs using a consumer group's regional coincident peak demand.

We have metering data for the direct billed and customers in the ASS and TOU consumer groups. For all other consumer groups (i.e., LOW, 015, and 360) we allocate the revenue requirement based on the consumer group's potentially controllable consumer.

For consumer groups without half-hour metering, we estimate regional coincident peak demand based on the upper South Island regional coincident peak demand, the network and half-hour regional coincident peak demand, as well as consumer group demand profiles.

Alignment between costs and prices

In this section, we discuss how we calculate prices for distribution, transmission, and pass-through components of our pricing. We use a combination of fixed, capacity, and variable pricing to recover distribution costs.

6.12 Day / Night variable volume-based charges

The variable volume-based charges have lower night rates than a day to offer incentives for shifting consumer into off-peak (night) periods. Where a consumer has a time of use meter or day/night meters, the actual usage is applied. Where a consumer has standard metering, consumption is split 70:30 days-to-night which is consistent with day/night consumption levels metered at GXPs on the network.

6.13 Fixed daily charges

Fixed daily charges are calculated by multiplying the total consumer group revenue requirement (target revenue) by the consumer group's fixed to variable ratio, and then dividing the fixed portion by consumer group ICP numbers. With ASS and TOU consumer groups, the fixed portion of the revenue requirement is multiplied by a demand charge ratio to calculate the portion of costs recovered through a demand charge.

The demand charge itself is calculated by dividing the total consumer group costs recovered from a demand charge, by either the consumer group's assessed capacity (in the case of the assessed groups) or the consumer groups after diversity maximum demand (for TOU groups).

6.14 Low fixed charge group prices

We calculate tariffs for the LOW consumer groups using a three-step process.

- We deduct from the LOW consumer group revenue requirement the total fixed charge we can recover under the low fixed charge regulations of $0.30 per day (2021/2022: $0.15 per day)
- We then calculate the LOW day-night variable prices using the corresponding 015 consumer group variable charges, so that the total annual price for an average consumer (consuming 9000 kWh p.a.) in the LOW consumer groups, is not higher than an average consumer would pay in the corresponding 015 groups
- We allocate the excess LOW user revenue requirement that we cannot recover under regulation to the remaining consumer groups

6.15 Calculating pass-through and recoverable prices

We recover a consumer group's forecast pass through and recoverable costs through 50% fixed charges and 50% variable volume-based charges. Pass-through and recoverable costs are not avoidable by changes to network use. As such, over time we will rebalance the proportion recovered using fixed and variable charges to rely more on fixed charges. We do not use a demand charge to recover these costs.

7. Assessing Consumer Impacts

We assess the impact on consumers of each change to the price structure and price level. We take account of:

- The potential the price change will result in bill shock for consumers or a consumer group
- Whether the price structure is practicable for retailers to adopt and apply
- The transaction costs associated with applying the price structure

7.1 Assessing impacts of price changes

We consider the impact of price changes on households and design our pricing to avoid bill shocks by ensuring, by consumer group, that the average bill in each consumer group is checked for reasonableness in comparison to the previous year.

Alpine's lines charge for mass-market customers will increase in 2022/2023 by an average of 0.7% compared to 2021/2022, whilst the lines charges for direct billed customers will increase by an average of 12% in 2022/2023.

Impact analysis focused on calculating the average annual and average daily decrease for each consumer group.

The average change in prices for each consumer group is shown in table 6 (refer to section 3).

As a final check, we check whether our prices are in the subsidy-free zone and are between incremental and standalone costs. We estimate the long-run incremental cost (LRIC) as $82/kW (if all costs were recovered through a demand charge) and the stand-alone cost as $721/kW (based on our assessment of the lowest cost alternative of supplying power to each consumer group).

Standalone cost is defined as the costs of an alternative power supply. We assume the standalone cost for each price group is $0.52/kWh for mass-market prices and $0.28/kWh for our Time of Use prices.

Our prices for all consumer groups are less than the estimated standalone cost.

7.2 Customer engagement

We conduct surveys to establish consumer preferences across a few different aspects such as outages, responsiveness, asset replacement, electric vehicle uptake, reliability of the electricity supply, and pricing.

Our last mass market survey was done in 2020 where we surveyed 500 mass market consumers pro-rated across our seven GXPs. The key conclusions were as follows

- 93% of respondents agreed or strongly agreed that their electricity supply is reliable
- 86% of respondents would prefer to pay about the same to have about the same reliability
- 76% of respondents agreed or strongly agreed that unexpected power outages are worse than planned power outages
- 68% of respondents agreed or strongly agreed that reducing the number of power outages is important
- 78% of respondents agreed or strongly agreed that reducing the length of power outages is important
- 86% of respondents agreed or strongly agreed that we should replace parts of the network before they fail
- 94% of respondents agreed or strongly agreed that advising of planned power outages ahead of time is important
- 88% of consumers do not expect to purchase an EV within the next five years
- 60% of respondents would allow Alpine to control their EV charging into cheaper periods.

We did not perform a mass market survey in 2021 but conducted one-on-one conversations with 13 of our consumers, including businesses, households, and retailers. The small test group was targeted to give us a better understanding, of the experience our consumers had with the services we provide. The three overarching core needs for consumers were:

- Reliable, safe, and affordable energy
- Collaboration and transparency always
- Simple and easy communication and support

The interviews revealed that our pricing methodology needs to evolve to ensure that we take sustainability goals, decarbonisation and consumer behaviour into account when setting prices. We are working on updating our pricing methodology for 2023/2024 and as part of that process will perform another mass market survey to ensure that we take the voice of our customers into account when developing our pricing methodology.

7.3 We set prices that are practicable for retailers to adopt and apply

Alpine considers the impact on retailers when adopting complex price structures. We, therefore, attempt to keep our pricing structure as uncomplicated and limited to as few categories as possible to reduce the need for retailers to interpret complex pricing or the need to upgrade their systems.

We consider our current pricing structure as easy to interpret. We also consider the appetite for retailers to pass through distribution pricing signals and access to smart meter data for pricing purposes.

8. Do you have any questions

We are happy to answer any questions about our pricing methodology that you might have. We can be contacted on 03 687 4300 or email us at analyst@alpineenergy.co.nz

8.1 After a copy of the pricing methodology

To get a copy of our Pricing Methodology you can go to our website at:

- www.alpineenergy.co.nz
- Call us at 03 687 4300, and we can email or post you a copy
- Visit our offices at 24 Elginshire Street, Washdyke between 8:30 am and 4:30 pm

8.2 Complaint process

If you have a complaint about our service, please contact us on 03 687 4300. We will respond to your complaint by:

- Confirming with you that you are making a formal complaint rather than wanting to talk through an issue with us
- Acknowledging the complaint within 2 working days
- Answering your complaint within 20 working days

If we can't resolve your complaint, you can contact Utilities Disputes Ltd, formerly known as the Electricity and Gas Complaints Commissioner, on http://www.utilitiesdisputes.co.nz or 0800 22 33 40.

Certification for the Year Beginning 1 April 2022 Disclosures

Pursuant to Schedule 17
Clause 2.9.1 of Section 2.9
Electricity Distribution Information Disclosure Determination 2012 (consolidated December 2021)

We, Warren McNabb and Linda Robertson being directors of Alpine Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

a) The following attached information of Alpine Energy's prepared for the purposes of clause 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.
b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

Warren McNabb
31 January 2022

Linda Robertson
31 January 2022

Appendix A: Alignment with the Electricity Authority's Pricing Principals

Pricing Principles	**Alpine Energy Limited's Alignment to the Principles**
a) Prices are to signal the economic costs of service provision by:	
i) Being subsidy-free (equal to or greater than avoidable costs, and less than or equal to standalone costs)	The prices for each load group are less than standalone costs. Prices for each load group are above the long-run incremental cost of supply. The assessment is in section 7.
ii) Reflecting the impacts of network use on economic costs;	Prices for each consumer group signal the impacts of network use on economic costs using TOU pricing (including day/night). Prices for commercial and industrial customers also signal economic costs of network use with a capacity charge which can vary annually based on changes to customer connection capacity or peak demand. Most network costs are fixed and do not vary based on network use in the short term (i.e., hourly, daily). Work is planned to clearly identify which network costs vary according to network use to confirm the correlation between fixed and variable costs and fixed and variable charges. Refer to section 2. Work is also planned to investigate pricing options to manage potential peak load increases.
iii) Reflecting differences in the network service provided to (or by) consumers	Prices reflect the difference in the network service provided to customers. We offer non-standard contracts for consumers with non-standard service requirements. Refer to section 4 for discussion of the approach to supply standards for customers with non-standard contracts. We define our load groups to reflect differences in network service provided, based on location and capacity prices for each load group are developed based on the cost to deliver the relevant network service. Refer to section 5, table 7 for a description of the network service provided to each load group.
iv) Encouraging efficient network alternatives	Network alternatives are considered as part of asset management planning. TOU prices are discounted for customers offering hot water control for peak load management. Refer to table 4 describing our pricing structures for each load group, and pages 24-25 describing the basis

<table>
<tr><td></td><td>for controlled and uncontrolled pricing.
Work is also planned to investigate pricing options to manage potential peak load increases.</td></tr>
<tr><th colspan="2">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</th></tr>
<tr><td colspan="2">Most network costs are fixed and do not vary based on network use in the short term. Work is planned to clearly identify which network costs vary according to network use to confirm the correlation between fixed and variable costs and fixed and variable charges. Refer to section 2.</td></tr>
<tr><th colspan="2">c) Prices should be responsive to the requirements and circumstances of end-users by allowing negotiation to:</th></tr>
<tr><td>i) Reflect the economic value of services</td><td>We offer non-standard contracts to consumers who have non-standard network connection and operation requirements to appropriately reflect the economic value to them of the network service. Refer to section 4 for discussion of the approach to supply standards for customers with non-standard contracts.</td></tr>
<tr><td>ii) Enable price/quality trade-offs</td><td>We regularly engage with consumers to test price/quality preferences via surveys. We also enable consumers to make price/quality trade-offs by offering controlled and uncontrolled prices. Refer to table 4 describing our pricing structures for each load group, and pages 24-25 describing the basis for controlled and uncontrolled pricing. Non-standard contracts are negotiated to reflect price/quality trade-offs. Refer to section 4 for discussion of the approach to supply standards for customers with non-standard contracts.</td></tr>
<tr><th colspan="2">d) Development of prices should be transparent and have regard to transaction costs, consumer impacts, and uptake incentives</th></tr>
<tr><td colspan="2">We regularly engage with consumers, retailers, shareholders on the construction of our delivery prices. In particular, we seek feedback from retailers on the practical implications of our pricing approach and any changes to pricing structures. We are managing the transaction costs on retailers by discussing pricing with other EBDs to help with the standardisation of tariffs, thereby reducing transaction costs for retailers and consumers.
We consider the impact of price changes on households and design our pricing to avoid bill shocks by ensuring by Load Group that the average bill in each Load Group is checked for reasonableness in comparison to the previous year. Increases to our delivery prices have been and will continue to be, consistent with the limits placed on us under the DPP Determination by the Commerce Commission.</td></tr>
</table>

Refer to section 7 for a discussion of the approach to assessing consumer impacts and engaging with retailers.

Appendix B: Alignment with EDB Information Disclosure Requirements

Pricing Principles	Alpine Energy Limited's Alignment to the Principles
2.4.1 Every EDB must publicly disclose, before the start of each disclosure year, a pricing methodology which-	
(1) Describes the methodology, in accordance with clause 2.4.3 below, used to calculate the prices payable or to be payable;	Refer to the description of the approach in this document.
(2) Describes any changes in prices and target revenues;	Refer to section 3, and table 6 for a description of the change in forecast revenue and average delivery prices for each consumer group between 2021/2022 to 2022/2023.
(3) Explains, in accordance with clause 2.4.5 below, the approach taken with respect to pricing in non-standard contracts and distributed generation (if any);	Refer to section 4 for a description of the pricing approach for non-standard contracts. Refer to section 4 for a description of the pricing approach for distributed generation.
(4) Explains whether, and if so how, the EDB has sought the views of consumers, including their expectations in terms of price and quality, and reflected those views in calculating the prices payable or to be payable. If the EDB has not sought the views of consumers, the reasons for not doing so must be disclosed.	Refer to section 7 for a description of how we sought the views of consumers on price and quality expectations and how these views inform the pricing approach.

2.4.2 Any change in the pricing methodology or adoption of a different pricing methodology, must be publicly disclosed at least 20 working days before prices determined in accordance with the change or the different pricing methodology take effect.	The pricing methodology remained unchanged, and this requirement is therefore not applicable for the current assessment period.
2.4.3 Every disclosure under clause 2.4.1 above must-	
(1) Include sufficient information and commentary to enable interested persons to understand how prices were set for each consumer group, including the assumptions and statistics used to determine prices for each consumer group;	Refer to section 5 for a description of the assignment of consumers to a load group. Refer to table 9 for a description of the method for allocating costs across consumer groups.
(2) Demonstrate the extent to which the pricing methodology is consistent with the pricing principles and explain the reasons for any inconsistency between the pricing methodology and the pricing principles;	Refer Appendix A.
(3) State the target revenue expected to be collected for the disclosure year to which the pricing methodology applies;	Refer to page 26 and table 8 for a statement of the target revenue for the year ending 31 March 2023.
(4) Where applicable, identify the key components of target revenue required to cover the costs and return on investment associated with the EDB's provision of electricity lines services. Disclosure must include the numerical value of each of the components;	Refer to table 8 for a statement of the key components of target revenue, and numerical values, for the year ending 31 March 2023.

(5) State the consumer groups for whom prices have been set, and describe: (a) the rationale for grouping consumers in this way; (b) the method and the criteria used by the EDB to allocate consumers to each of the consumer groups;	Refer to section 5 and table 7 for a description of consumer groups, the reason for allocating consumers to a group, and allocation the method.
(6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the difference in respect of each of those reasons;	Refer to section 3 for a description of changes to price levels for 2022/23, including the reasons for the change. Refer to table 6 for quantification of the change for each consumer group.
(7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;	Refer to section 6 for a description of the method for allocating target revenue among consumer groups. Refer to table 10 for the target revenue for each load group.
(8) State the proportion of target revenue (if applicable) that is collected through each price component as publicly disclosed under clause 2.4.18.	Refer to table 11.
2.4.4 Every disclosure under clause 2.4.1 above must, if the EDB has a pricing strategy-	
(1) Explain the pricing strategy for the next 5 disclosure years (or as close to 5 years as the pricing strategy allows), including the current disclosure year for which prices are set;	As described in section 2.3, revising our pricing strategy will be a key strategic focus for us over the next 12 months, during which we will, after consultation with retailers, determine a medium and long-term pricing strategy. We will disclose the pricing strategy in our pricing methodology disclosures for 2023/2024.
(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;	
(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	
2.4.5 Every disclosure under clause 2.4.1 above must-	

(1) Describe the approach to setting prices for non-standard contracts, including–	
a) extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be collected from consumers subject to non-standard contracts;	Refer to section 4 for a description of the pricing approach for non-standard contracts. For the period ending 31 March 2022, we had six direct billed customers with 12 ICPs connected to our network at present. We are not expecting any new direct billed connections before 31 March 2023. Refer to table 10 for the expected target revenue to be recovered from non-standard contract customers.
b) how the EDB determines whether to use a non-standard contract, including any criteria used;	Refer to section 4 for a description of the pricing approach for non-standard contracts, including criteria used. The decision to place a new connection onto a direct billed contract is made on a case-by-case basis.
c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology is consistent with the pricing principles;	Refer to section 4 for a description of the pricing approach for non-standard contracts, including the approach to cost allocation and determining pricing. Prices for non-standard contracts are developed to be consistent with the pricing principles. Price structures for non-standard contract consumers reflect a close alignment between fixed and variable costs.

(2) Describe the EDB's obligations and responsibilities (if any) to consumers subject to non-standard contracts in the event that the supply of electricity lines services to the consumer is interrupted. This description must explain— a) The extent of the differences in the relevant terms between standard contracts and non-standard contracts; b) Any implications of this approach for determining prices for consumers subject to non-standard contracts;	Refer to section 4 for a description of the service levels available to consumers subject to non-standard contracts, including the extent of differences to standard consumers.
(3) Describe the EDB's approach to developing prices for electricity distribution services provided to consumers that own distributed generation, including any payments made by the EDB to the owner of any distributed generation, and including the— a) Prices; and b) Value, structure, and rationale for any payments to the owner of the distributed generation.	Refer to section 4 for a description of the approach to developing prices for network services provided to consumers with distributed generation.

Appendix C: Loss Factors

Losses represent the percentage of electricity entering the network that is lost during the delivery to ICPs. The quantity of electricity metered at ICPs is net of losses. To determine each retailer's purchase responsibilities, the electricity measured at the consumer's meter is multiplied by a 'loss factor'.

There are two main components to loss factors:

- Fixed component due to the standing losses of the zone substation and distribution transformers
- Variable components arising from the heating effects of the resistive losses in the delivery conductors[22]

The loss percentage reported under the information disclosure requirements for the year ended 31 March 2021 was 4.3%.

Losses can vary by connection

The following loss factors applied by us are as follows:

Loss category code	Description	Loss factor effective 1 April 2022
ALV	Total Alpine network general (non-SS) load at 0.4 kV customer service lines segment	1.049
A11	Total Alpine network general (non-SS) load at 11 kV HV network segment	1.019
A33	Total Alpine network general (non-SS) load at 33 kV HV network segment	1.020
AOP	Opuha site specific generator injecting at sub transmission segment	0.969
A11SS1	Fonterra Studholme site specific load supplied via 11 kV HV network segment (W297)	1.004
A11SS2	Fonterra Studholme site specific load supplied via 11 kV HV network segment (W367)	1.012
AMP1	Mountain Power embedded network site specific load at 11 kV HV network segment (MP1)	1.005
AMP4	Mountain Power embedded network site specific load at 11 kV HV network segment (MP4)	1.010

22 The resistive losses are proportional to the square of the load current and occur in all network conductors and in the zone substations and distribution transformers.

Losses for 11kV consumers will be 3% less than 400V consumers because there are no distribution transformer losses. Dedicated 33kV line provides N -1 security to meet reliability of supply requirements results in effective losses of less than 2% for loads around 15MW.

Glossary

ABY	Albury grid exit point/zone substation
ADMD	After Diversity Maximum Demand
AMP	Asset Management Plan
BPD	Bell's Pond grid exit point/zone substation
Capex	Capital Expenditure
Code	The Electricity Industry Participation Code 2010
CPD	Coincident peak demand
CPI	Consumer Price Index
DPP	Default Price-Quality Path
EDB	NZ Electricity Distribution Businesses
GIS	Geographic Information System
GWh	Giga Watt hours
GXP	Grid Exit Point
HCA	High-cost area
ICP	Installation Control Point
IRIS	Incremental rolling incentive scheme
kV	kilo Volt
kVA	kilo Volt Ampere
LCA	Low-cost area
LV	Low Voltage
MW	Mega Watt
N-1	Reliability measure, where n systems can lose 1 element and still function normally

ODV	Optimised Deprival Valuation
OLTC	On Load Tap Changer
OPEX	Operating Expenditure (including maintenance spend)
RAB	Regulatory asset base
RCPD	Regional Coincident Peak Demand
STU	Studholme grid exit point
TIM	Timaru grid exit point/step-up zone substation
TKA	Tekapo grid exit point
TMK	Temuka grid exit point/zone substation
TOU	Time-of-use
TWZ	Twizel grid exit point
V	Volts
WACC	Weighted average cost of capital