Pricing Methodology

For Delivery Prices effective as at 1 April 2020

Pursuant to the requirements of clause 2.4
of the Electricity Information Disclosure Determination 2012
(consolidated in 2015)

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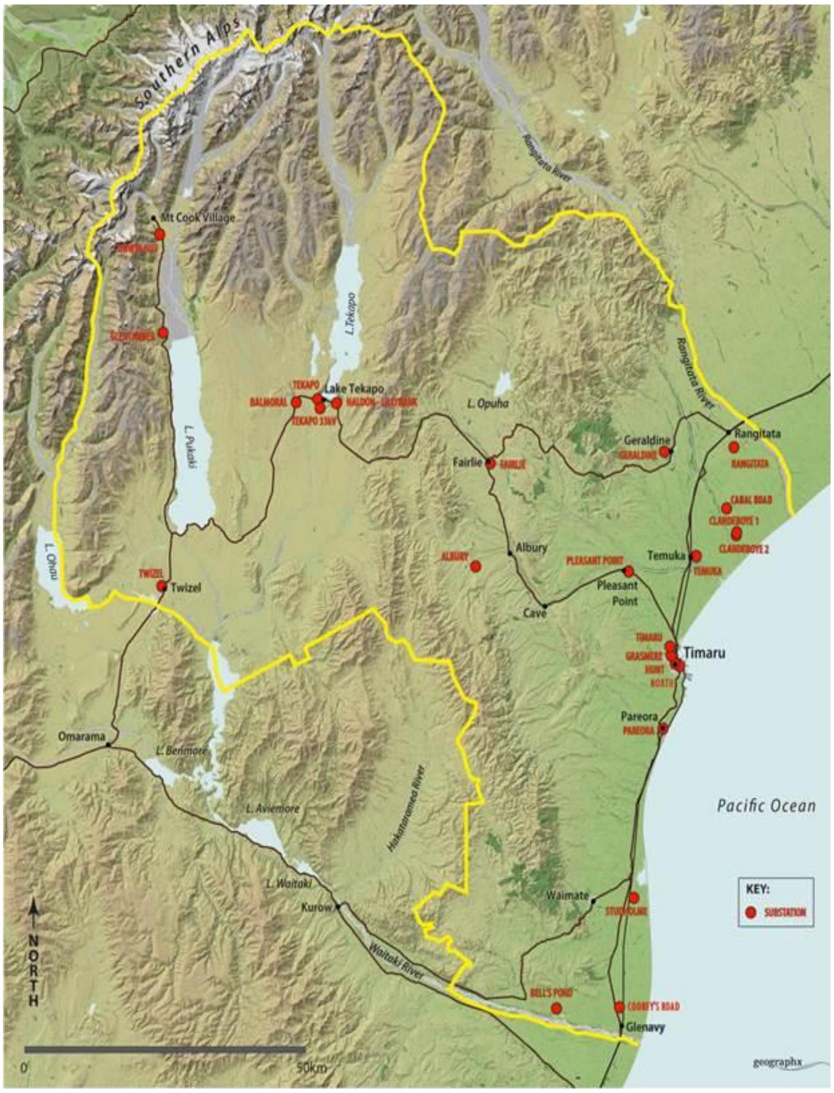
1. About Alpine Energy

We supply electricity to over 33,302 individual connection points throughout South Canterbury. Our area of supply covers approximately 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.

Figure 1 Alpine Energy network, and location of the seven GXPs and 24 substations on our network



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

- Timaru District Council (47.5%)
- Line Trust South Canterbury (40%)
- Waimate District Council (7.54%)
- Mackenzie District Council (4.96%).

Since many of our consumers are also ratepayers to the local councils, they benefit directly from our revenue, through an annual dividend payment and indirectly, through services provided by local councils.

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 2020.

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 distribution charges.
- Pass through charges such as rates, levies and wash-up charges that we must pay throughout the year.
- Transpower's transmission charges.
- Definitions of these charges are provided in the Glossary.

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, in the most efficient and fair way possible.

- 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 pricing as consumer preferences and technology change how our network is used.
- Section 3 describes changes we made to our pricing approach and prices for 2020-21.
- Section 4 describes how we set 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.

Network characteristics

The main drivers influencing electricity demand in our area relate to weather and economic activity. Economic activity in our area of operation strongly influences the configuration of our network.

Electricity is delivered to our network via seven grid exit points (GXPs) with Transpower and one embedded generator at the Opuha dam. The total energy consumed in 2018/19 was 817 GWh. Energy consumed varies from year to year depending on wet or dry irrigation seasons, and severe or mild winters. The coincident peak demand (CPD) is presently 140MW. Growth in CPD has been approximately 2.49% per year over the last 18 years.

More detail on the network characteristics for the seven supply areas is outlined in Table 1.

Table 1 Network characteristics for the seven supply areas (GXPs)

Measure	ABY	BPD	STU	TKA	TMK	TIM	TWZ
ICPs	1663	634	3313	18228	948	6891	1625
Zone substations	2	2	1	4	5	3	1
Peak demand (MW)	4.58	14.15	14.12	4.66	56.22	65.19	4.00
Energy consumption (GWhr)	11.22 -16.47*	45.49	62.28	21.46	284.67	364.14	15.86

*due to Opuha Generation

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.

The demand for new connections during 2019 was constant even after the improvement in milk pay-outs from the dairy companies, and a reduction in irrigation connections. Growth in demand is generally driven by irrigation, industrial, commercial, and domestic subdivision connections and extensions. Lately we have had much activity in the area of subdivisions and industrial development. With the government withdrawing support for the Hunter Downs irrigation scheme, we have experienced a reduction in the number of on farm irrigation developments

Table 2 Main load type and forecast capacity adequacy for main supply areas (GXPs) summarises the main load type and forecast capacity adequacy for each supply area.

Table 2 Main load type and forecast capacity adequacy for main supply areas (GXPs)

Location / GXP	Load type and forecast capacity adequacy
Albury	Small townships, sheep & beef farming, some dairying. Adequate capacity to meet a small growing demand
Bells Pond	Dairy processing and on farm dairying irrigation. Adequate capacity to meet the growing demand
Studholme	Sheep and beef farming, some dairying.
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
Temuka	Temuka and Geraldine townships, and dairying irrigation. Adequate capacity to meet a small growing demand. Major replacements and upgrades will be required if there is an increase in Fonterra's dairy factory demand requirements
Timaru	Timaru – residential, commercial and light industrial. Upgrading supply to Washdyke industrial area. Adequate capacity to meet growing demand

Source: Alpine Energy Limited, 2019 Asset Management Plan

More detail on our network characteristics is in our Asset Management Plan, available at https://www.alpineenergy.co.nz/__data/assets/pdf_file/0018/8541/ALPINE-ENERGY-AMP-2019.pdf.

The network is experiencing congestion in some areas from distributed generation exporting into the network. In 2017 we surpassed 1 MW in PV solar installations on our network and even though 2017 saw a reduction in the number of installations, applications picked up in 2018 with a record number of installations and overall capacity. We have also connected our second bio gas distributed generator on our network and expect this type of installation to increase due to the large number of dairy farms across our network and the increasing pressure on farmers to reduce carbon emissions.

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.

Consumer characteristics

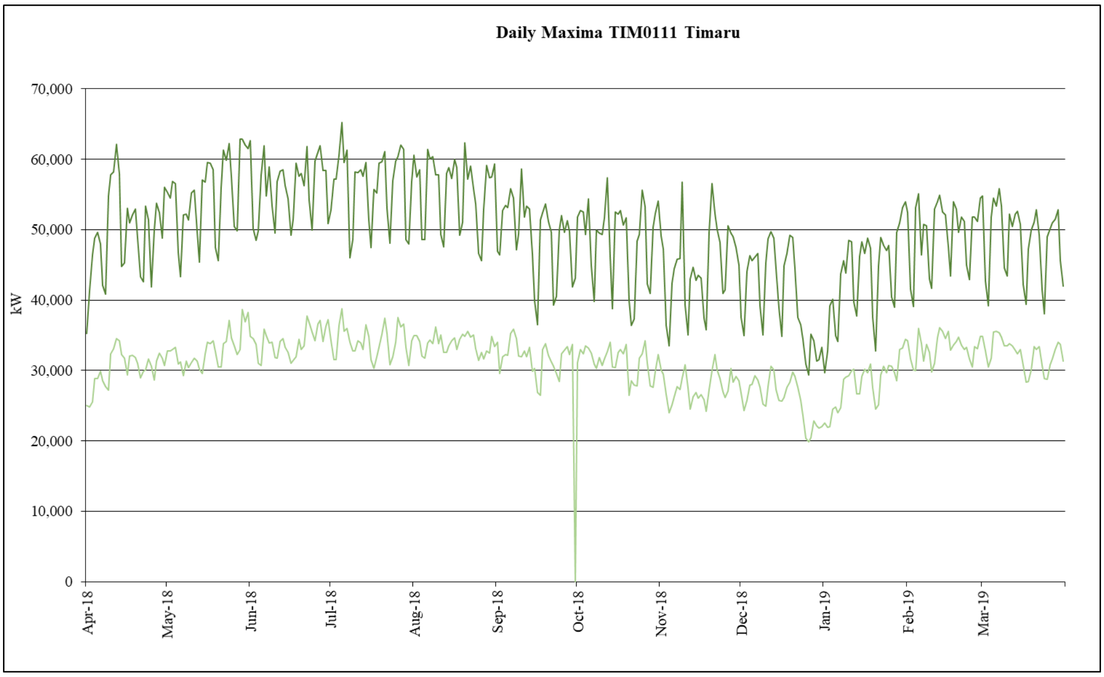
With our network covering an area between the Rangitata and Waitaki rivers, from the coast all the way to Mt Cook, we supply the communities of Timaru, Temuka, Waimate, and MacKenzie basin and surrounding areas. There are currently 19 retailers operating on our network. Almost 42% of our consumers are 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.

Table 3 ICP count and percentage of total by region at 31 March 2019

Location	ICP Count	%
Timaru	16,037	48%
Waimate	3,706	11%
Temuka	3,489	10%
Geraldine	3,049	9%
Twizel	1,635	5%
Pleasant Point	1,269	4%
Fairlie	1,183	4%
Lake Tekapo	827	2%
Pareora	473	1%
Orari	302	1%
Glenavy	264	1%
St Andrews	235	1%
Winchester	224	1%
Cave	208	1%
Albury	182	1%
Makikihi	112	0%
Mount Cook	107	0%
Grand Total	33,302	100%

The Timaru GXP constitutes almost half of the Alpine Network connection points and consumption which is primarily residential, commercial and small industrial customers. Figure 2 shows the load profile for Timaru.

Figure 2 Daily maximum and minimum demand for Timaru April 2018 to March 2019



Winter peak loading occurs mainly at Timaru and Tekapo GXPs, although other 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 early 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.

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.

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, [2019] NZCC 21,* 27 November 2019 (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 3 April 2018), 3 April 2018 (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 of February 2010. Appendix A describes how our pricing approach aligns with the Pricing Principles.

- We are required to set prices for distributed generator 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 primary residence consumers a low fixed charge tariff option (of 15 cents/day) by the Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004 (the low fixed charge regulations). The Electricity Authority monitors and enforces the 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.

Our delivery prices are set taking account of the network, consumer and regulatory characteristics relevant to our network. As such, we recognise the importance of evolving pricing as circumstances and characteristics change, and plan to evolve our pricing to reflect evolving consumer expectations, technology choices, and use of the network.

Current pricing

Our delivery prices for the majority of consumers have a three-part structure, with a fixed daily charge component, and two variable components with a volume-based charge for daytime usage (7am to 11pm) and a volume-based charge for night-time usage (11pm to 7am).

Delivery prices for connections with time-of-use metering, and capacity greater than 15kVA have a four-part structure, with an additional fixed kw/day capacity charge component.

An overview of the current price structure and price components for each consumer groups is provided in Table 4. More detail on each consumer group is provided in section 6.

Table 4 Overview of current price structure and price components for each consumer group 2020/21

Consumer group	Forecast # ICPs	Description	Fixed component	Fixed component	Variable component	Variable component
			$/day	**$/kW/day**	**$/kwh - day**	**$/kwh - night**
LOWHCA	1863	Households using <9000kWh/year, controlled, high cost area	$0.15		$0.12	$0.08
LOWLCA	10238	Households using <9000kWh/year, controlled, low cost area	$0.15		$0.12	$0.08
LOWUHCA	16	Households using <9000kWh/year, uncontrolled, high cost area	$0.15		$0.14	$0.10
LOWULCA	37	Households using <9000kWh/year, uncontrolled, low cost area	$0.15		$0.13	$0.10
015HCA	6120	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU	$1.43		$0.07	$0.03

Consumer group	Forecast # ICPs	Description	Fixed component	Fixed component	Variable component	Variable component
		metering, controlled, high cost area				
015LCA	12415	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, controlled, low cost area	$1.29		$0.07	$0.03
015UHCA	34	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, uncontrolled, high cost area	$1.93		$0.07	$0.03
015ULCA	42	Households and small commercial, 0-15kVA, < 60amp fuse, no TOU metering, uncontrolled, low cost area	$1.77		$0.07	$0.03
360HCA	542	Households and Commercial, 3 phase, 60 amp connection, no TOU metering, controlled, high cost area	$6.07		$0.07	$0.03
360LCA	768	Households and Commercial, 3 phase, 60 amp connection, no TOU metering, controlled, low cost area	$4.38		$0.07	$0.03
360UHCA	15	Households and Commercial, 3 phase, 60 amp connection, no TOU metering, uncontrolled, high cost area	$6.45		$0.07	$0.03
360ULCA	16	Households and Commercial, 3 phase, 60 amp connection, no TOU metering, uncontrolled, low cost area	$4.88		$0.07	$0.03
ASSHCA	1356	Commercial and Industrial, capacity > 15kVA, high cost area	$1.98	$0.10	$0.07	$0.03
ASSLCA	417	Commercial and Industrial, capacity > 15kVA, low cost area	$1.35	$0.09	$0.07	$0.03
TOU400HCA	38	Commercial and Industrial connected to LV network, TOU metering, high cost area	$1.39	$0.42	$0.02	$0.01
TOU400LCA	102	Commercial and Industrial connected to LV network, TOU metering, low cost area	$1.10	$0.29	$0.02	$0.01
TOU11HCA	6	Commercial and Industrial, connected to 11kV	$1.15	$0.25	$0.03	$0.01

Consumer group	Forecast # ICPs	Description	Fixed component	Fixed component	Variable component	Variable component
		network, TOU metering, high cost area				
TOU11LCA	4	Commercial and Industrial, connected to 11kV network, TOU metering, low cost area	$ 1.11	$ 0.33	$ 0.02	$ 0.01

The fixed daily charge is set based on costs which are regarded as sunk costs.

The fixed charges are set to recover:

Operating Expenditure

- Reliability, safety and environment
- Routine and corrective maintenance and inspection
- System operations and network support

Business Support

- Depreciation
- Revaluations
- Regulatory Tax

A portion of pass through and recoverable and transmission costs

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

Operating Expenditure

- Asset relocations
- Asset replacement and renewal
- Service Interruptions and emergencies
- System Growth
- Vegetation management.

A portion of pass through and recoverable and transmission costs

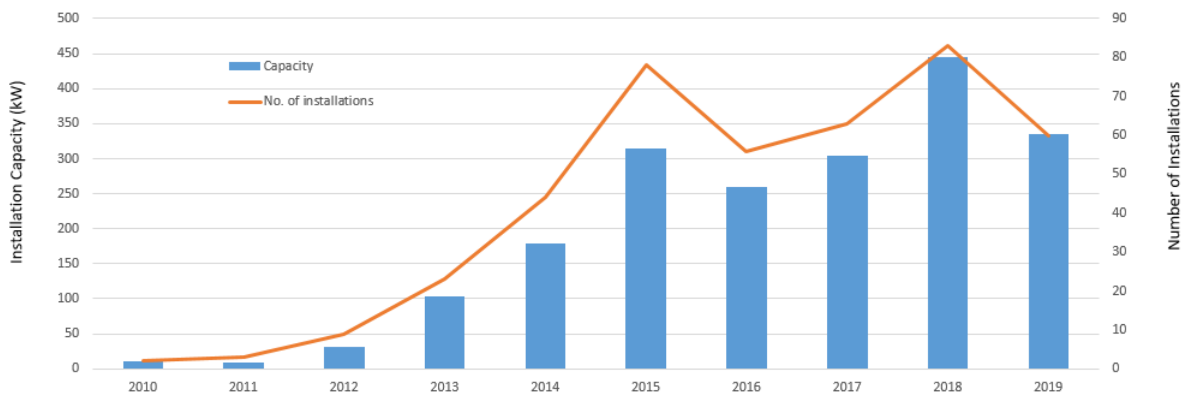
Evolving our pricing and prices – our strategy

Our delivery prices are set to reflect our circumstances and the cost of delivering a safe, reliable electricity supply. We recognise the importance of evolving our pricing and prices as circumstances change.

The overarching factor influencing our thinking of how our pricing could evolve over time is the integral role our network plays in economic development in South Canterbury. In particular, we expect ongoing changes to use of our network from dairying, irrigation, commercial and industrial development around Timaru, and tourism around Twizel and Tekapo.

We also expect consumer-led uptake of new technologies, such as photovoltaics, batteries and electric vehicles, to influence use of our network, and our pricing. The number and capacity of photovoltaic distributed generators installed on our network continues to increase although erratic year on year, and in some locations can cause network operation issues due to export congestion. Figure 3 shows the rate of new distributed generators uptake since 2011.

Figure 3: Number and capacity of new distributed generators



However, we expect our network will continue to be the main source of getting electricity to our consumers, with distributed energy resources and enabling technology for network support rather than network replacement. We are looking to align ourselves with others in the industry doing research, trials and experimentation with new technologies at a network level, to benefit from their resources and capabilities.

Finally, regulatory circumstances are influencing our pricing, with an initial 14.6% decrease from 2019/2020 to 2020/2021 and a projected 8.22% increase in allowed revenue over the 5 year period for 2020/21 to 2025/26, resulting from the Commerce Commission's Default price path Determination in November 2019.

The following factors will also influence our pricing strategy and the direction of our future pricing:

- Outcomes and implementation of the Electricity Price Review[1]
- Review of the Low User Fixed Charge Regulations
- Guidance from the Electricity Networks Association working groups
- Government policies to reduce emissions.

Pricing changes being considered

We are considering several changes to our pricing approach to reflect changing network and consumer characteristics of our network. In brief, we are considering:

- Options to address efforts to avoid charges through short-term disconnection, e.g., irrigators disconnecting during the winter. We think the underlying issue is the fixed charges which consumers pay when not using irrigation pumps over the winter months. The Alpine portion of the charge makes up the majority of a consumer’s power bill when not being used. These charges cover fixed operating and monthly Transpower charges.
- Options to address issues associated with non-residential and other ineligible consumers being included in the low user load group. The underlying issue is the incentive created by the Low user regulations to avoid charges.
- Options to address issues relating to the Assessed (“ASS”) price code category. The underlying issue is only a small number of consumers in this load group have half hourly meters, resulting in assessed demand charges being set once only when the connection is livened.

We will be looking at these issues, and the options, during 2020. Changes, if any, would be included in our published 2021 Pricing Methodology after the appropriate consultation with customers.

Implementation and transition planning

We want to make sure changes to our pricing approach and pricing is implemented effectively, and without adverse impact for consumers or customers, particularly retailers.

We will develop implementation and transition plans for changes to our pricing as part of considering pricing issues and options.

Key to our implementation and transition planning is obtaining comprehensive half-hourly data. We started collecting more comprehensive monthly TOU data from 1 April 2019 when we changed billing practices. Additionally, we are currently rolling out smart meters across our network. These meters give real-time information about consumers’ half-hour energy

[1] https://www.mbie.govt.nz/assets/electricity-price-review-final-report.pdf

usage. Once the rollout is complete, real-time information on all load groups' usage will be available. We will require further industry collaboration in order to obtain detailed ICP consumption data from retailers to be able to use it for pricing purposes.

Our current delivery prices do not reflect the information that will be available after the roll-out is complete. We intend to consider how our delivery charges might be structured in a way that anticipates and enables us to use this information when it becomes available. Changes, if any, would be included in our published 2021 Pricing Methodology after the appropriate consultation with customers.

Longer-term pricing direction

We expect use of our network to change as consumer preferences, economic growth and other factors change how our network is used. We recognised our pricing approach needs to evolve at the same time to avoid creating perverse outcomes which stop the full value of our network, and consumer preferences, from being realised.

We will be guided by the Electricity Networks Association pricing work in determining our longer-term pricing direction. Specific things we will consider for 2022 and the longer-term to make sure our pricing approach evolves as network and consumer characteristics evolve are:

- Introducing a power factor charge. 70 ICP's in November 2019 had an average Power Factor below 0.95.
- Introducing EV charger charges once there is sufficient uptake of Electric Vehicles in South Canterbury.
- Introducing distributed generation charges once we are able to obtain sufficient smart meter data for customers making use of, or importing electricity into the Alpine Network.

Seasonal and Temporary Disconnection Fee - Charges to consumers are allocated on the basis of a full Price Year and therefore apply for the full Price Year to recover ongoing fixed costs. If an installation is reconnected within 12 months from the date of any disconnection the Distributor may, at its discretion, apply a connection fee equivalent to the fixed charges applicable during the period of disconnection. Currently we are exposed if Irrigators disconnect for the winter.

3. Pricing changes for 2020/21

We are changing delivery prices in 2020/21 as follows:

- We are reducing prices across all consumer price categories

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

Our allowable distribution revenue for 2020/21 is $42.65 Million.

The median delivery price decrease from 1 April 2020 to 1 April 2021 is 16%. The decrease is attributable to:

i) The maximum allowable revenue for distribution set at $42.65 million
ii) Transmission charges decreased to $12.57 million
iii) Pass through and recoverable costs decreasing to $3.55 million

The change in revenue for each consumer group, and average delivery price change from the resulting changes to price levels is described in Table 5.

Table 5 Change in forecast revenue and average delivery prices between 2019/20 and 2020/21

Consumer group	Change in revenue 19/20 to 20/21 ($)	Change in revenue 19/20 to 20/21 (%)	Average delivery price change (%)
LOWHCA	-$125,578	-9.75%	-$ 130.57
LOWLCA	-$806,535	-11.96%	-$ 126.88
015HCA	-$1,526,466	-19.59%	-$ 219.51
015LCA	-$3,583,095	-23.10%	-$ 214.28
360HCA	-$387,308	-17.48%	-$ 505.96
360LCA	-$684,382	-21.40%	-$ 732.44
ASSHCA	-$10,124,796	-45.62%	-$ 2,935.22
ASSLCA	-$2,016,464	-34.25%	-$ 4,580.85
TOU400HCA	-$628,588	-25.41%	-$ 17,531.86
TOU400LCA	-$2,048,838	-32.63%	-$ 20,354.55
TOU11HCA	-$677,938	-35.43%	-$ 119,844.22

Consumer group	Change in revenue 19/20 to 20/21 ($)	Change in revenue 19/20 to 20/21 (%)	Average delivery price change (%)
TOU11LCA	-$283,367	-26.88%	-$ 69,755.79

The average change in prices is due to:

- the DPP3 maximum allowable revenue set by the Commerce Commission.
- A reduction in transmission charges due to a combination of a reduction in Transpower's recovery set by the Commerce Commission and having recovered unclaimed charges during 2019-2020 which no longer apply in 2020-2021.

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

Changes to price structure

We have not changed any price structures for the current year. However, as noted in section 2, we are considering reviewing and possibly discontinuing the Assessed Load Group in future years given that we are unable to assess the demand charges on an annual basis for non-half hour customers.

Alpine Energy has applied the reduction in allowable revenue to the variable component of pricing, thereby reducing the proportion of revenues recovered through variable charges, and increasing the proportion of revenues recovered through fixed charges. The changes will improve alignment of our pricing with our costs of supply, which are primarily fixed.

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

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 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.

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 total forecast allowed revenue we can recover for the year. Forecast revenue is determined by the Commerce Commission to reflect efficient costs of supplying distribution services

- Calculate expected costs for the year. The main component costs are operating costs (including administration costs), capital costs (including return on investment) and transmission costs (including ACOT)

- Allocate costs to each consumer group to as closely as possible align 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.

Non-standard pricing for direct billed customers

For the period ending 31 March 2020, we had six direct billed customers (12 ICPs) connected to our network at present. We are not expecting any new direct billed connections before 31 March 2020.

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 take into account 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[2]. Because we enter into long term contracts with direct billed customers we are able to negotiate outcomes which are consistent with market like arrangements.

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 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.

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 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 midyear cash flow.

Capital contributions based on perceived risk of 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.

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.

Recovering the cost of existing network assets

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

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

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 line/cable length to the total line/cable lengths in the network.

For sub-stations, transformers, protection, and switchgear, costs are apportioned to the asset using the total demand or capacity[3] of all users of 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.

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 under-recovery of our required revenue.

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 the consumer is connected to. 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.

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[4]. 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.

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

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

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 less 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.

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[5].

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 March 2019 connected to our network were:

- 375 small distributed generators installed at residential or commercial premises at a combined capacity of 1.7 MVA
- one embedded generator that generates at 8 MW[6].

Fees payable by distributed generators to us are set by the Electricity Authority under the *Electricity Industry Participation Code* (the Code)[7]. We neither 'pay', or 'charge', distributed generators for the electricity that they convey down our lines. 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, although in accordance with the Code, connection, inspection and livening fees still apply. This is an alternative to paying Avoided Cost of Distribution benefits.

Avoided Cost of Transmission (ACOT) payments are made by contract on a case by case basis.

Information about connection to our network and our application process for connection and operation of distributed generation by both small and large distributed generators is available

5 www.alpineenergy.co.nz

6 Opuha hydro installation with maximum generation of 9 MW.

7 Schedule 6.5, Electricity Participation Code 2010, Part 6, Connection of distributed generation.

on our website[8].

5. Consumer groups

We assign our 'standard consumers' to one of 13 load groups for pricing.

We supply our standard consumers under our use of system agreements we have with electricity retailers. Our current agreement takes into account the Electricity Authority's principles taken from its Model Use of System Agreement, published in 2003.

The majority of the consumers on our network are standard consumers.

Assigning standard consumers into load groups

Table 6 lists the 13 load groups, and their defining characteristics. Consumers are assigned to a load group based on location, capacity of connection, maximum business day peak demand and meter configuration.

Table 6: Load groups

Load 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
015HCA	0-15kVA and up to 60 Amp fuse – high-cost area
015LCA	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
ASSHCA	Assessed demand over 15kVA – high-cost area
ASSLCA	Assessed demand over 15kVA – low-cost area
TOU400HCA	Time of use 400 volt supply – high-cost area
TOU400LCA	Time of use 400 volt supply – low-cost area
TOU11HCA	Time of use 11kV supply – high-cost area
TOU11LCA	Time of use 11kV supply – low-cost area

8 http://www.alpineenergy.co.nz/our-network/sub-menu-modid-156/40-solar-distributed-generation

Load group	Description
IND	Individually assessed sites – Directly Billed Customers

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:

i. on each transformer
ii. per kilometre of distribution line length.

As a general rule low-cost area density, in ICPs per transformer, is 13 times greater than high-cost area density.

Allocation of consumers to load groups within cost areas

Consumers in the high-cost area and the low-cost area are split into the following load 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.

Low Fixed Charge load group

We must comply with the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004*, which state that we must offer a fixed tariff for 'domestic' consumers of no more than $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 load groups that pay a daily fixed price of $0.15. We also ensure that an 'average' consumer[9] in the Low load groups pays no more than an 'average' consumer in an alternate 015 load group, by adjusting the costs allocated to the Low user load groups. This means the low user group pay less than the costs of supply, with these costs met by other consumers.

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

015, 360, and Assessed demand load groups

ICPs not in the Low fixed charge load groups and without half hour, time of use (TOU) meters[10] installed, fall into one of three load groups:

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

ICPs in the 015 load 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 load groups are connected with three phase 60 A connections'. ASS load groups have a maximum capacity per phase greater than 60 A. This can include two phase connections also. Demand charges for consumers in the ASS load 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 and is dependent on obtaining detailed meter data from retailers.

Time of use load groups

ICPs in the TOU load 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 coincident (network) peak demand (CPD), which are used to allocate costs to load groups, and calculate demand charges.

Uncontrolled load

Uncontrolled load tariffs are charged to consumers in the LOW, 015, and 360 load groups whose electrical hot water heating load we are not permitted to control during periods of high demand. The uncontrolled load tariff is in place to incentivise consumers to offer up controllable load. Controllable load is critical for us during supply emergencies, and to avoid further investment in network capacity.

The low user groups pay an additional variable charge of $0.0209 cents per kWh, for both day and night variable charges, for uncontrollable load. 015 and 360 consumers pay an additional annual fixed charge of $187.69 for uncontrollable load.

[10] Some ICP's in the assessed load groups may have half hour metering installed but choose to remain in the assessed group.

6. Allocating costs across consumer groups

We set prices for by calculating and allocating costs across each specific consumer group. The process involves:

- confirming the total forecast revenue allowed by the Commerce Commission for the pricing year
- identifying our major cost components, and whether the costs are fixed or avoidable
- allocating costs to specific consumer groups
- checking alignment between cost types and price components.

Total forecast revenue

Our total required revenue recovers annual distribution, transmission, and pass through and recoverable costs, shown in Table below[11].

Table 7: Revenue requirement for the year ending 31 March 2020

Network-related costs	In $'000
Operating expenditure	20,033
Depreciation	14,358
Return on capital	5,394
Regulatory tax	2,868
Pass-through costs and recoverable costs	3,552
Transmission	12,574
Total revenue requirement	**58,778**

Major cost components

Our distribution revenue requirement recovers annual regulated network costs for the period 1 April 2020 to 31 March 2021 and includes:

- depreciation
- operating expenditure
- revaluations
- return on investment
- regulatory tax
- transmission
- pass-through and recoverable costs.

[11] Please note the forecast business costs are in 2018/19 dollar terms when prices are set.

Each cost component is discussed in more detail below.

Depreciation

Depreciation is calculated on a straight-line basis in accordance with ID Determination using a standard life for the asset[12]. Depreciation costs for the year ending 31 March 2021 are forecast using historical depreciation on our regulatory asset base (RAB sourced from schedule 4 of the 2019 Information Disclosures Schedules[13].

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.

Forecast maintenance costs for the year ending 31 March 2021 are derived from our 10-year network Opex budget, found in schedule 11b of the 2019 to 2029 Asset Management Plan.

Revaluations of the regulatory asset base

Our regulatory asset base (RAB) is revalued by—

> 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.

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 2021. A vanilla WACC (67^{th} percentile) of 4.23% has been applied.

Our RAB, as at 31 March 2019 was $201,5 million. This is an increase of approximately $1.9 million when compared to the value of our RAB as at 31 March 2018.

Regulatory tax

We recover regulatory tax through our distribution charges. The forecast regulatory tax value for the period ending 31 March 2021 is $2.9 million and was sourced from the Commerce

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12 Standard lives for each asset group is 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

13 The schedules can be found at www.alpineenergy.co.nz/corporate/disclosures

Commission forecasts for DPP3[14].

Transmission costs

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.

Pass-through and recoverable costs

Pass through and recoverable costs include:

- Rates
- Levies: Commerce Commission, Electricity Authority, and Utilities Disputes
- IRIS Adjustment for the current year
- Pass-through balance from the period ended 31 March 2019.

We forecast the rates and levies based on historical averages. The pass-through balance is sourced from our Annual Compliance Statement for the year ending 31 March 2019.

Allocating costs to specific consumer groups

The revenue allocated to each load group for the year ending 31 March 2021 is shown in Table 8: Target revenues per load group.

We allocate the required revenue to load groups using cost allocators described in Table 9: Cost allocators used and rationale for selection.

Table 8: Target revenues per load group

Load group	Year ending 31 March 2021 Target Revenue $'000	Year ending 31 March 2020 Target Revenue $'000	Growth in Target Revenue	Proportion of Load Group Target Revenue to Total Target Revenue
LOWHCA	1,163	1,289	-126	2%
LOWLCA	5,935	6,741	-806	10%
LOWUHCA	13	16	-3	0%
LOWULCA	20	19	1	0%

[14] Commerce Commission website, https://comcom.govt.nz/regulated-industries/electricity-lines/projects/2020-2025-default-price-quality-path, Workbook Financial-model-EDB-DPP3-final-determination-27-November-2019.xlsx

015HCA	6,266	7,793	-1,527	11%
015LCA	11,930	15,513	-3,583	20%
015UHCA	42	48	-6	0%
015ULCA	47	64	-17	0%
360HCA	1,829	2,216	-387	3%
360LCA	2,514	3,198	-684	4%
360UHCA	72	88	-16	0%
360ULCA	49	54	-5	0%
ASSHCA	12,068	22,193	-10,125	21%
ASSLCA	3,871	5,888	-2,017	7%
TOU400HCA	1,845	2,474	-629	3%
TOU400LCA	4,230	6,279	-2,049	7%
TOU11HCA	1,235	1,913	-678	2%
TOU11LCA	771	1,054	-283	1%
IND	4,878	5,310	-432	8%
Total	**58,778**	**82,150**	**-23,372**	**100%**

Table 9: Cost allocators used and rationale for selection

Cost Component	Allocator	Rationale
Operating expenditure	ADMD Weighted RAB	Opex is related to the consumers use of the network in terms of required capacity and utilisation (demand). Opex is allocated to load groups based on after diversity maximum demand. 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 Weighted RAB	Impact of any over or under-recovery under the price cap is allocated to load groups based on after diversity maximum demand. Total cost is allocated to asset sub-categories based on the weighted average of each ODV asset category to the total

Cost Component	Allocator	Rationale
		regulatory assets base.
Revaluations and sundry income	NA	Revaluations are recovered through return on investment component, which takes into account the revaluation of the RAB each year.
Depreciation	ADMD Weighted Depreciation	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 group's after diversity maximum demand. Total cost is allocated to asset sub-categories based on the weighted average of each ODV asset category to the total depreciation.
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. Therefore these costs are allocated evenly amongst ICPs, with the exception of individual customers who pay an allocation of shared costs based on contractual terms.
Transmission	ADMD RCPD	Transmission charges are allocated to non-standard consumers based contribution to the regional coincident peak demand—new investment and connection charges and after diversity maximum demand—interconnection charges Transmission charges are allocated to standard consumers based on each 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 load groups based on ICP count

Allocating distribution costs

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

We do this by allocating costs based on each load group's demand we do this as demand is the main cost driver of distribution costs.

We allocate network costs by the load groups after diversity maximum demand.

Allocating pass–through and recoverable costs

When calculating load 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 load groups, by multiplying the forecast annual pass through and recoverable cost by the number of ICPs in a load group to total ICPs on the network.

Allocating transmission costs

When calculating load group prices to recover annual transmission costs, we use Transpower's transmission costs effective from 1 April 2020. From the total, we remove the annual transmission revenue we expect to recover from direct billed customers, before allocating the remainder to load 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 load). We allocate connection and new investment agreement costs to load groups using a load group's after diversity maximum demand, and interconnection costs using a load group's regional coincident peak demand.

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

For load 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 load 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.

Calculating distribution prices

We use a combination of fixed and variable pricing to recover distribution costs. The reasons for having both fixed and variable charges are explained at

Table .

Table 10: The fixed variable cost recovery ratio

Advantage of fixed variable ratio	Rationale
Signal future cost of capacity upgrades	A variable charge signals the cost of using the network at peak times for those consumers without TOU metering. A large fixed charge (without demand charges[15]) discourages efficient use of the network as it does signal the cost of using the network at peak times Alpine have found that these distribution pricing signals are rarely, if at all passed through by retailers.
Recognition of cost structures	A large fixed cost aligns with the fact that the majority of network costs in the short run are fixed.
Protecting revenue from reduction in consumption	Recovering revenue through fixed charges reduces the risk that revenue falls due to a reduction in consumption.

For consumers without TOU metering we have adopted a ratio of approximately 50% fixed to 50% variable cost recovery.

Where consumers have time of use metering, we recover approximately 60% of charges through a demand charge and the remainder through fixed and variable charges.

Day / night variable charges

We recover variable charges with lower night rates than day, to offer incentives for shifting load 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.

Fixed daily charges

Fixed daily charges are calculated by multiplying the total load group revenue requirement by

[15] We fix demand charges for the pricing year and therefore include demand charges as a fixed annual cost when calculating the fixed variable ratio. In this instance however we are discussing fixed charges less demand charges.

the load group's fixed to variable ratio, and then dividing the fixed portion by load group ICP numbers. With ASS and TOU load 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 load group costs recovered from a demand charge, by either the load group's assessed capacity (in the case of the assessed groups) or the load groups after diversity maximum demand (for TOU groups).

Low fixed charge group prices

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

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

Calculating pass through and recoverable prices

We recover a load group's forecast pass through, and recoverable costs through 50% fixed charges and 50% variable charges. We do not use a demand charge to recover these costs.

Calculating transmission prices

We recover pass through and recoverable costs through fixed, demand, and variable (consumption) charges. For those consumers in the 015 and 360 load groups with uncontrolled hot water, we add an increase to their fixed daily charge of $0.514219. For consumers in the LOW user groups, we increase their variable charges by $0.0209 / kWh.

7. Assessing consumer impacts

We assess the impact on consumers of each change to 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.

Assessing impacts of price changes

The average distribution charge, including transmission, for residential consumers is about 35% of their total electricity bill], and about 1% average household income.

The demographic profile of our network is diverse. We consider the impact of price changes on households, and to 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.

As a final check, we check whether our prices are in the subsidy-free zone and are between incremental and standalone cost. 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 a power to each consumer group).

Standalone cost is defined as the costs of 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.

Customer engagement

In July 2019 we conducted a ‘mass market’ consumer survey. We received completed responses in regard to views on supply reliability, inconvenience caused by interruptions, community disruption, and price. We also tailored the questions to seek feedback on power bills and electric vehicles. The previous consumer survey was in February 2017.

The key message from most consumers across all market segments indicate there is still a limited interest in electric vehicles over the next 5 – 10 years depending on price and would prefer to charge their vehicles off-peak times at home. Customers would generally be more accepting of a fixed bill from Alpine. We will take these perspectives into account in when considering our longer-term pricing direction.

At best, there are seemingly isolated market segments and industrial customers that have some willingness to have solar panels or batteries installed, but seem unwilling to alter the time of their demand or operate on-site generation. Section 4 on how prices are set and Distributed generation details the number of distributed connection on the Alpine Network.

We set prices which 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

After a copy of the pricing methodology?

To get a copy of our Pricing Methodology you can:

- go to our website at https://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.

Complaints Process

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

(i) confirming with you that you are making a formal complaint rather than wanting to talk through an issue with us

(ii) acknowledging the complaint within 2 working days

(iii) 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 on 0800 22 33 40.

Certification for the year beginning 1 April 2020 disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012 – (consolidated in 2015)

We, Stephen Richard Thompson and Don Mcgillivray Elder, being directors of Alpine Energy Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

The following attached information of Alpine Energy's prepared for the purposes of clauses 2.4.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

a) 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.

Stephen Richard Thompson	Don Mcgillivray Elder
14 February 2020	14 February 2020

Appendix A: Alignment with Pricing Principles

Table 7: Electricity Authority Pricing Principles

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 (prices are lower than standalone costs)	Refer section 7. Our prices are lower than standalone costs. Any attempts to be completely subsidy free is inhibited by the Low User Fixed Charge regulation. However will work towards being subsidy free when the regulations allow for it. Current pricing has endeavoured to minimise cross subsidisation and will continue to improve to do so.
ii) reflecting the impacts of network use on economic costs;	Refer sections 4-6. We use TOU pricing (including day night) and capacity/demand based pricing where possible to encourage consumers to use the network outside of peak periods where capacity constraints may occur. Our prices are set to reflect costs of supply.
iii) reflecting differences in network service provided to (or by) consumers	Refer sections 4 and 5. We offer non-standard contracts for consumers with non-standard service requirements. We define our load groups to reflect differences in network service provided, based on location and capacity.
iv) encouraging efficient network alternatives	Refer sections 4 and 6. Our prices include price components designed to encourage efficient network use, including providing incentives for load control through and supporting investment in distributed energy resources. Our distributed generation connection and pricing policies support efficient investment in distributed generation.
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	
Refer sections 2 and 6. Our prices are designed to use fixed charges to recover fixed costs, and variable charges to recover avoidable costs. However, we recognise consumer preferences and technology are changing network use, and are considering options to evolve our pricing approach and prices.	
c) Prices should be responsive to the requirements and circumstances of end users by allowing negotiation to:	

i) reflect the economic value of services	Refer sections 4 and 7. We offer non-standard contracts to consumers who have non-standard network connection and operation requirements so as to appropriately reflect the economic value to them of the network service. For standard consumers, we set prices to be less than the standalone cost of supply.
ii) enable price/quality trade-offs	Refer sections 2 and 7. 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. Non-standard contracts are negotiated to reflect price/quality trade-offs.

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

Refer section 7. We are of the view that our delivery prices are understandable for stakeholders (for example, consumers, retailers, shareholders, and us). Our delivery prices have been developed in a manner that intends to promote certainty and price stability.

When we have had to increase delivery prices we have done so uniformly with due regard given to the impact on stakeholders of any changes in prices and/or transaction costs. Consumers have a reasonable expectation that our delivery prices will be stable and will not shift significantly over time. 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.

We are managing the transaction costs on retailers by discussing pricing with other EBD’s in order to help with standardisation of tariffs, thereby reducing transaction costs for retailers and consumers.

Appendix B: Alignment with Information Disclosure requirements

Table referencing section of document demonstrating alignment with ID 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 description of approach in this document.
(2) Describes any changes in prices and target revenues;	Refer section 3
(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 section 4
(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 section 7
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.	

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 description of our pricing approach described in the document.
(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 section 3
(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 section 6
(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 section 5
(6) If prices have changed from prices disclosed for the immediately preceding disclosure year, explain the reasons for changes, and quantify the	Refer section 3

difference in respect of each of those reasons;	
(7) Where applicable, describe the method used by the EDB to allocate the target revenue among consumer groups, including the numerical values of the target revenue allocated to each consumer group, and the rationale for allocating it in this way;	Refer sections 5 and 6
(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 section 6
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;	Refer section 2
(2) Explain how and why prices for each consumer group are expected to change as a result of the pricing strategy;	Refer section 2
(3) If the pricing strategy has changed from the preceding disclosure year, identify the changes and explain the reasons for the changes.	Refer section 2
2.4.5 Every disclosure under clause 2.4.1 above must–	
(1) Describe the approach to setting prices for non-standard contracts, including– (a) the extent of non-standard contract use, including the number of ICPs represented by non-standard contracts and the value of target revenue expected to be	Refer section 4

collected from consumers subject to non-standard contracts;	
(b) how the EDB determines whether to use a non-standard contract, including any criteria used;	Refer section 4
(c) any specific criteria or methodology used for determining prices for consumers subject to non-standard contracts and the extent to which these criteria or that methodology are consistent with the pricing principles;	Refer section 4
(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 section 4
(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 section 4

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:

i) fixed component due to the standing losses of the zone substation and distribution transformers

ii) variable components arising from the heating effects of the resistive losses in the delivery conductors[16].

The loss percentage reported under the information disclosure requirements for the year ended 31 March 2019 was 1%.

Losses can vary by connection

The following loss factors applied by us are as follows:

- 33kV dedicated—1.02
- 11KV general—1.05
- 400V general—1.07

Losses for 11kV consumers will be some 2% 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. N-1 security refers to the ability to provide power even after the loss of one transformer.

[16] 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.

Glossary

ACOD	Avoided Costs of Distribution – A reduction in distribution costs when demand for power is reduced at network peak times or provided by local generation during network peak times
ACOT	Avoided Costs of Transmission – A reduction in transmission costs when demand for power is reduced at transmission peak times or provided by local generation during transmission peak times
ADMD	After Diversity Maximum Demand—the simultaneous maximum demand of a group of consumers with similar power requirements
Capacity	The maximum power supplied by a network asset. With respect to consumer capacity, it refers to the size of the network assets directly connected to the consumer.
Code	The Electricity Industry Participation Code 2010
Consumer	A person that consumes electricity supplied by our network
Commerce Commission	A government body tasked with regulating our price and quality of service
CPD	Coincident Peak Demand—relates to the consumer's off-take at the connection location during a peak demand period
CPI	Consumer Price Index—a measure of the change of a weighted average of prices in a basket of consumer goods and services
Customer	A legal entity with which we have a direct contractual relationship, in the form of a use of supply agreement (e.g. retailers and large consumers)

Delivery prices	Prices that recover distribution, transmission, pass through and recoverable costs.
Demand	The amount of electricity required to power equipment at a point in time, expressed in kilowatts (kW) or kilovolt amperes (kVA)
Distributor	Alpine Energy Limited as the operator and owner of the electricity distribution network
Distributed Generation	Electricity generation that is connected and distributed within the distribution network, the electricity generation being such that it can be used to avoid or reduce transmission demand costs. Also referred to as 'embedded generation'
Distribution costs	Costs associated with building and maintaining our electricity network
Distribution network	The network of electricity assets that distribution network companies such as Alpine Energy own and operate, to deliver electricity from the transmission network to consumers.
DPP	Default Price-Quality Path—with which non-exempt suppliers of electricity line services comply under Part 4 of the Commerce Act 1986
EDB	Electricity Distribution Business—a business that is responsible for delivering electricity from the national grid to consumers
Electricity Authority	A government body tasked with promoting efficiency in the electricity industry and who make changes to the Electricity Industry Participation Code, which we must comply with
Fixed prices	Prices which do not vary with the amount of kWh consumed
GIS	Geographic Information System—is used to isolate assets on a network and to identify low cost and high cost areas

GXP	Grid Exit Point—a point of connection between Transpower's transmission system and our distribution network
HCA	High cost area – an area of the network which has higher distribution costs per ICP than the LCA due to lower ICP density
High voltage	Network assets that supply electricity at or above 11,000 V
ICP	Installation Control Point—a point of connection on the Distributor's network, which the Distributor nominates as the point at which a retailer is deemed to supply electricity to a consumer
LCA	Low cost area – an area of the network which has lower distribution costs per ICP than the HCA due to higher ICP density
Load group	A group of consumers with similar network connection characteristics such as location or capacity requirements
Low user	A consumer in a Low load group
Low voltage	Network assets that supply electricity at 400 V
Long run incremental costs	LRIC The increase in cost from an increase in network capacity that has occurred over a period of time long enough for all costs to be variable.
Mass market	The majority of electricity consumers, predominantly residential and small business
Network asset	An asset that is primarily used to transport electricity between the national transmission grid and local consumers of electricity
Part 4	Part 4 of the Commerce Act 1986 governing the regulation of EDBs

	as administered by the Commerce Commission
Pass through and recoverable costs	Costs which are charged to Alpine Energy which are then 'passed through' consumers. Costs include: • rates • commerce commission levies and other industry levies • transmission costs
Pricing Principles	Guidelines published by the Electricity Authority that specify the information that a Distributor should make available
RAB	Regulatory Asset Base - The value our network assets would have in a competitive market if this existed, as determined by the Commerce Commission
RCPD	Regional Coincident Peak Demand —relates to the consumer's off-take at the connection location during a regional peak demand period
Required revenue	The revenue we require to cover the annual costs of providing electricity distribution services
TOU	Time Of Use—is a consumer that is metered according to their electricity consumption for a particular period (usually half-hourly) allowing pricing that varies depending on time of day and measurement of peak demands
Transmission costs	The cost of maintaining the national electricity grid. Transmission costs are charged to distribution companies who recover these costs from users of the network through delivery prices
Uncontrollable Load	The load that we are not able to control i.e., switch off during periods of high demand such as electrical water heating
Vanilla WACC	Weighted average of the pre-corporate tax cost of debt and the cost of equity
Variable prices	Prices which vary with the amount of kWh consumed

WACC	Weighted Average Cost of Capital—is the regulated rate of return on the company's assets.