Alpine Energy limited

Pricing Methodology

For line charges, effective as at 1 April 2015

Pursuant to the requirements of clause 2.4 of the Electricity Information Disclosure Determination 2012

Certification for Year-beginning Disclosures

Pursuant to Schedule 17

Clause 2.9.1 of section 2.9

Electricity Distribution Information Disclosure Determination 2012

We, Stephen Richard Thompson and Alister John France, 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 Limited prepared for the purposes of clause 2.4.1, disclosure of pricing methodologies, 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.

Stephen Richard Thompson	Alister John France
9 March 2015	9 March 2015

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Glossary

ADMD	After Diversity Maximum Demand—the simultaneous maximum demand of a group of homogeneous consumers, divided by the number of consumers
Code	The Electricity Industry Participation Code 2010
Consumer	A person that consumes or acquires electricity lines services
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 user of supply agreement for example, retailers and large consumers
Demand	The rate of expending electrical energy 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'
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
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
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

Part 4	Part 4 of the Commerce Act 1986 governing the regulation of EDBs as administered 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
Pricing Principles	Guidelines published by the Electricity Authority that specify the information that a Distributor should make available
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
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
WACC	Weighted Average Cost of Capital—is the regulated rate of return on the company's assets.

1. Introduction

This pricing methodology outlines our approach to the setting of line charges effective from 1 April 2015.

Our network

We are an electricity distribution business (EDB) located in the South Canterbury region of New Zealand.

Our network has a replacement value of more than $153.2 million, and connects approximately 31,000 consumers through seven local grid exit points (GXPs) at: Bells Pond, Temuka, Timaru, Studholme, Albury, Tekapo, and Twizel. Figure 1 shows the location of the seven GXPs and substations on our network.

Figure 1: Map of our network

We are owned by the community we serve

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

- Timaru District Council (47.5%)
- LineTrust South Canterbury (40%)
- Waimate District Council (7.54%)
- MacKenzie District Council (4.96%).

Our ownership structure means that our consumers are our shareholders. As shareholders our consumers both benefit directly, through an annual dividend payment and indirectly, though services provided by local councils.

Our pricing is regulated

In 2015 prices charges by EDBs are subject to the following regulations:

- Commerce Commission, under Part 4 of the *Commerce Act 1986* (Part 4):
  - *Electricity Distribution Services Default Price–Quality Determination 2015* (DPP Determination)
  - The Commerce Commission's *Electricity Distribution Information Disclosure Determination 2012* (IDD2012)
- Electricity Authority under:
  - the *Electricity (Low Fixed Charge Tariff Option for Domestic Consumers) Regulations 2004* (the low fixed charge regulations)
  - Part 6 of the *Electricity Industry Participation Code 2010* (the Code), relating to the pricing of distributed generation.

We are of the view that our pricing methodology is consistent with the above regulations. More detailed discussion of how we meet the Electricity Authority's pricing principles can be found in section 12 at page 22.

2. Overview of our Pricing Methodology

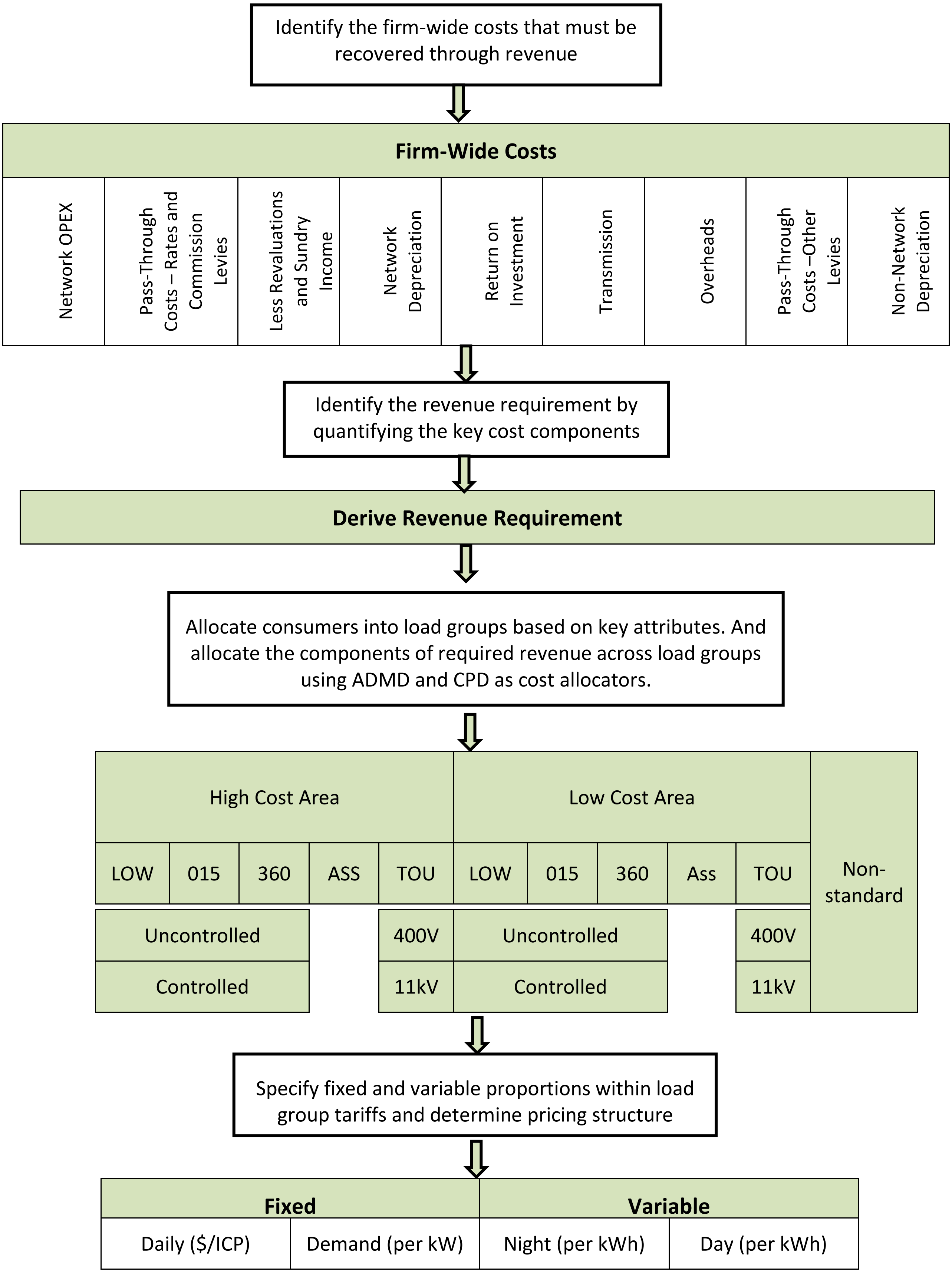
Our Approach to Pricing

We develop our prices through a five step process.

1. Identify the costs that must be recovered through prices.
2. Identify the revenue required by quantifying the key cost components.
3. Determine the key attributes of each load group and assign consumers into load groups for the purposes of allocating costs.
4. Allocate the revenue required across our load groups using appropriate cost allocators.
5. Specify fixed and variable proportions within load group tariffs and determine the pricing structure.

Our five steps are summarised in Figure 2, over page.

Figure 2: Key steps of our pricing methodology



Our approach to pricing and the method for calculating the revenue requirement has remained unchanged since 2010. We are of the view that our approach aligns to good industry practice for the allocation of costs across load groups.

We do not currently have a formal pricing strategy

Our approach remains unchanged from previous years in that we intend to set prices that comply with the price path under the DPP Determination as determined by the Commerce Commission.

3. Our revenue requirement

Our revenue requirement is based on the recovery of our full costs including the return on investment in our network. The revenue requirement from which prices are calculated, effective from 1 April 2015, is made up of the following:[1]

	In $'000
Operating expenditure	15,240
Pass-through costs—i.e., rates and levies	299
Recovery of revenue forgone from RCP1[2]	4,984
Revaluations and sundry income	-2,786
Depreciation	8,308
Return on investment	8,972
Transmission	15,730
Additional allowance	563
Total revenue requirement	**51,311**

Components of Revenue Required

Operating expenditure

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

- maintenance
- quality of service.

Maintenance costs are derived from our network maintenance programme, which is driven by safety requirements, security of supply objectives, fault response, and repair.

[1] Please note the forecast business costs are in 2014/15 dollar terms.

[2] Regulatory control period 1(RCP1) was for the period 1 April 2010 to 31 March 2015.

Our Asset Management Plan (AMP) contains details of our planned maintenance programme and 10 year forecast expenditure for each component of Opex.[3]

Pass-Through Costs – i.e., rates and levies

We incur costs through paying council rates and levies to the Commerce Commission and to the Electricity Authority. The DPP Determination allows us to pass these costs through to consumers as we have no or very little control over these costs.

Recovery of revenue foregone from RCP1

To minimise price shocks the Commerce Commission have capped price increases since 1 April 2012. The price cap has meant we have not been able to increase prices to a level by which we can fully recover our costs. To enable us to 'catch–up' for this under recovery the DPP Determination allows us to recover our under recovered costs from last regulatory period this regulatory period[4].

Revaluations and sundry income

Where components of the regulatory asset base have been revalued upwards it is recognised as revenue. Because this revenue is not recovered through prices we must deduct it from our required revenue. For the same reason sundry income must also be deducted from the revenue required.

If revaluations and sundry income were included in the revenue required, the total revenue required would be more than target revenue.

Depreciation

Depreciation is calculated on a straight–line basis in accordance with our accounting policies. To determine the amount of depreciation the carrying value of network property, plant and equipment is divided by the standard life[5] for that asset. This information is sourced from our fixed asset register.

Return on investment

Our return on investment has been calculated using the regulated WACC on the network regulatory asset base in line with the DPP Determination. A vanilla WACC (67th percentile) of 7.19% has been applied.

Our regulatory asset base, as at 31 March 2015, is approximately $160.9 million. This is an increase of approximately $4.1 million when compared to the value of our regulatory asset base in the prior year. The replacements of assets that have reached their useful lives and growth on our network have contributed to the increase in our regulatory asset base over the last year.

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[3] A copy of our AMP can be found on our website at http://www.alpineenergy.co.nz/disclosures/sub-menu-modid-159/49-assett-management-plan

[4] Regulatory control period (RCP2) is for the period 1 April 2015 to 31 March 2020.

[5] 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.

Transmission

In accordance with the current regulatory regime, we pass through all the transmission charges to consumers at cost. Transmission charges include:

- connection charges—annual capacity charges
- interconnection charges—coincident peak charges
- new investment charges—determined as per the agreement between us and Transpower as to capacity and security upgrades.

Additional allowance

The Commerce Commission has given us, and two other electricity distribution businesses[6], an additional allowance to account for forecasting uncertainty[7]. The additional allowance recognises that the costs of submitting a customised price-quality path to address forecast uncertainty are in our instances prohibitive.

4. Our Load Groups

Standard Consumers

Our 'standard consumers' are those consumers that can be assigned to one of our 13 load groups (shown at Figure 2, page 7 above) who have a supply contract with a retailer and do not have an individual supply agreement with us.

We supply our standard consumers under our use of system agreement that we have with the 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.

Allocating Standard Consumers into Load Groups

We have 13 load groups as shown in Table 1 at page 11. Consumers are assigned to a load group based on:

i) location—i.e., high cost area or low cost area
ii) fuse size at the individual connection point (ICP)
iii) maximum business day peak demand
iv) meter type—for example, half hour metering is mandatory for consumers within the TOU load group.

[6] OtagoNet Limited and The Lines Company.

[7] Commerce Commission, Default price-quality paths for electricity distributors from 1 April 2015 to 31 March 2020, Main Policy Paper, 28 November 2014, paragraph X25.

Table 1: Load groups

Load Group	Description
LOWHCA	Domestic consumers[8] that consume less than 9,000 kWh per annum – high cost area
LOWLCA	Domestic consumers that consume 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
IND	Individually assessed sites

High Cost and Low Cost area allocation

For standard consumers the revenue requirement is initially allocated to high cost areas (HCA) and low cost areas (LCA) using our geographic information system (GIS). The HCA and LCA represents the variable factors i.e., the number of consumers:

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

High voltage (HV) assets are shared across each region by demand. However a greater proportion of low voltage assets (LV) are allocated to high cost areas in recognition of lower connection density.

The vast majority of our consumers are located in the urban centres of:

- Timaru
- Waimate
- Temuka
- Geraldine
- Fairlie
- Tekapo
- Twizel.

[8] The objective of the low fixed charge regulations is to ensure that electricity retailers offer a low fixed charge tariff option or options for delivery electricity to **domestic consumers at their principal place of residence** that will **assist low-use consumers and encourage energy conservation**. [emphasis added]

Connections in rural areas represent approximately 30% of total consumers, 41% of annual consumption, and 47% of installed capacity. This suggests that urban and rural connections are distinguishable by their use of network assets and profiles, as well as by connection density. As a general rule urban density is thirteen times greater than rural density.

Allocation to load groups within cost areas

Consumers in high cost areas and low cost areas are then split up into the following load groups:

- a low fixed charge group
- mass market installed capacity groups:
  - 015—a 0-15 kVa single phase 60 Amp connection
  - 360—45 kVa three phase 60 Amp connection
- an assessed demand group based on fuse size, motor nameplate, measured or connected load
- time of use groups for LV and 11kV connections.

Low Fixed Charge load group

Our approach to complying with the low fixed charge regulations is to have a separate low fixed charge load group for consumers using less than 9,000 kWh per annum.

Installed capacity is used to determine network utilisation

The 015, 360, and assessed demand load groups all recognise the installed capacity at the consumers ICP. The installed capacity is used as a proxy to determine consumers' utilisation of the network.

The 015 and 360 load groups determine utilisation by the number of connected phases. Consumers with three phase connections have much higher load characteristics than those with single phase connections in terms of annual consumption (i.e., installed kW and after diversity maximum demand (ADMD)).

The assessed demand load groups rely on an engineering assessment of the demand associated with the connection. A consumer's assessed demand level can be obtained by that consumer on request.

Tine of Use load groups

Consumers in the TOU load groups have a fixed charge, by unit of maximum demand which recognises asset utilisation of peak demand specific voltage assets. These consumers are then split into LV and 11kV load groups to reflect that consumers who only use HV circuits and equipment (i.e., 11kV) are not required to contribute to the costs of the LV network that they do not utilise.

Uncontrolled load

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

The low user groups pay an additional variable charge of $0.0266 cents per kWh, for both day and night variable charges, for uncontrollable load. 015 and 360 consumers pay an additional fixed charge of $239.24 per annum for uncontrollable load.

The premium of uncontrollable load is to signal to consumers the importance that the electricity market places on controllable load. Load control enables us to manage our network as well as the transmission peaks. By managing the transmission peaks we are able to avoid transmission costs, a saving which we pass through to the consumers that give us load control.

Non–Standard Consumers

We consider 'non–standard consumers' to be those consumers that we bill directly and with which we have an individual agreement. The consumers form the IND load group as they are individually assessed. We currently have four non–standard consumers with target revenue of approximately $5.2 million for the 2015/16 year.

The decision to enter into an individual agreement with a consumer is made on a case–by–case basis. We have not formalised our approach to pricing non–standard consumers as we have found that each consumer has sufficiently unique needs. Therefore addressing a formalised pricing approach would provide little or no benefit.

Non–standard consumer group prices are determined by negotiation and are netted off the revenue required.

5. Allocation of our revenue requirement

Costs that are directly attributable to a group are allocated to the group that created them. This helps achieve prices that fall within incremental cost and standalone cost. Shared costs are allocated to consumers based on the main driver of the costs being allocated.

Network Costs Allocated to Network Assets

Network costs (excluding transmission) are not directly attributed to load groups. These costs are first allocated to HV network assets and LV network assets.

LV assets are allocated to high cost areas based on coincident peak demand (CPD) and the remaining costs are allocated to low cost areas. HV assets are not allocated to a particular area. From here the costs can be allocated to load groups.

LV assets include:

- distribution switchgear
- distribution substations
- distribution transformers
- and low voltage lines.

HV assets include:

- sub-transmission
- zone substations
- distribution lines and cables
- distribution switchgear
- and customer service connections.

Load Group statistics

Table 2 shows ICP numbers, ADMD, CPD, and regional coincident peak demand (RCPD), as at 31 March 2014, for each load group. This information is used to allocate required revenue to load groups.

Table 2: Load group statistics as at 31 March 2014

Load group	ICP numbers	Consumption (MWh)	ADMD (MW)	CPD (MW)	RCPD (MW)
LOWHCA	1,115	5,645	3.58	0.51	2.03
LOWLCA	7,216	35,643	22.85	3.26	13.06
015HCA	6,793	60,924	21.83	3.12	12.47
015LCA	16,137	127,933	52.02	7.43	29.73
360HCA	488	11,882	9.24	4.40	2.20
360LCA	751	22,636	14.36	6.84	3.42
ASSHCA	1,228	115,593	86.99	37.06	5.62
ASSLCA	385	37,380	34.22	11.58	4.21
TOU400HCA	36	16,096	6.12	3.94	3.65
TOU400LCA	114	91,047	22.50	12.42	11.51
TOU11HCA	7	23,601	5.80	4.53	2.87
TOU11LCA	4	16,664	4.07	3.02	1.92
IND	4	150,839	29.10	28.30	5.38
Total	**34,278**	**715,884**	**312.67**	**126.41**	**98.06**

Distribution and transmission charges associated with non–standard consumers are netted off network costs in proportion to these consumers' use of assets and share of transmission costs, respectively.

Revenue requirement allocated to load groups

Table 3 compares 2015/16 revenue allocations to the previous period's allocations, and reflects reallocation of required revenue as well as changes in load profiles.

Table 3: Allocation of revenue requirement to load groups

Load Group	2015/16 Target Revenue (in millions)	2014/15 Target Revenue (in millions)	Growth in Target Revenue (in millions)	Proportion of required revenue collected from each Load Group
LOWHCA	0.55	0.54	+0.01	1.1%
LOWLCA	3.34	3.36	-0.02	6.5%
015HCA	5.49	5.53	-0.04	10.8%
015LCA	11.92	12.02	-0.10	23.4%
360HCA	1.26	1.06	+0.19	2.5%
360LCA	1.75	1.65	+0.11	3.4%
ASSHCA	11.26	9.91	+1.35	22.1%
ASSLCA	3.41	3.27	+0.14	6.7%
TOU400HCA	1.18	1.07	+0.10	2.3%
TOU400LCA	4.48	4.75	-0.27	8.8%
TOU11HCA	1.14	1.15	-0.01	2.2%
TOU11LCA	0.76	0.79	-0.03	1.5%
IND	4.46	3.48	+0.97	8.7%
Total	**51.00**	**48.58**	**+2.40**	**100%**

Using the methodology outlined above, the required revenue for 2015/16 is allocated to load groups as set out in Table 3 at page 16.

How we allocate costs

We have allocated the components of the revenue requirement to load groups using the cost allocators as set out in Table 4.

Table 4: Cost allocators used and rationale for selection

Cost Component	Allocator	Rationale
Operating expenditure	ADMD CPD	The incurrence of network Opex is represented through the consumers' contribution towards the assets' overall utilisation. Therefore demand related allocators have been used. LV related costs are allocated to load groups based on ADMD and HV related costs are allocated to load groups based on CPD.
Pass through costs – i.e., rates and levies	ADMD CPD	LV related costs are allocated to load groups based on ADMD and HV related costs are allocated to load groups based on CPD.
Recovery of revenue forgone from RCP1	ADMD CPD	LV related costs are allocated to load groups based on ADMD and HV related costs are allocated to load groups based on CPD.
Revaluations and sundry income	ADMD CPD	Revaluations arise from the indexation of fixed assets which is related to the investment driven by each load group. Therefore demand related allocators have been used. LV related costs are allocated to load groups based on ADMD and HV related costs are allocated to load groups based on CPD.
Depreciation	ADMD CPD	Depreciation represents the return of investment. These costs are allocated based on the investment driven by each consumer group (their contribution to the network peak). HV related depreciation is allocated to groups based on CPD with LV related depreciation allocated to groups based on ADMD.
Return on investment	ADMD CPD	LV related costs are allocated to load groups based on ADMD and HV related costs are allocated to load groups based on CPD. These costs have been allocated on the basis of the investment driven by each consumer group via their demand and contribution to the network peak. This reflects the significance of the assets on which a return is sought.
Transmission	RCPD CPD	Transpower levies interconnection charges based on RCPD and connection charges based on AMD. We have allocated interconnection charges based on RCPD in line with Transpower. However we have allocated our connection charges using CPD.

6. Our pricing structure

Our tariff mix includes a fixed and variable component

The Ministry of Commerce guidelines suggest 100% fixed line charges are appropriate as the cost structures for electricity distribution businesses are almost 100% fixed. Whereas the Electricity Authority's pricing principles suggests that a 50:50 ratio between fixed and variable is appropriate so as to send a pricing signal to consumers to encourage demand side management[9].

We comply with the Electricity Authority's pricing principles by:

- recovering 50% of our costs through a fixed component that ensures all consumers contribute to cost recovery; and
- recovering 50% of our costs through a variable component that sends an appropriate signal to consumers of the impact that their demand has on our future investment costs.

The benefits of using a 50:50 ratio are described at Table 5.

Table 5: benefits of including a 50:50 ratio of fixed and variable components in our prices

Advantage realised	Disadvantage avoided	Discussion
Variable charges signal the future cost of capacity upgrades.	A large fixed charge discourages efficient use of energy and capacity.	Where TOU metering is unavailable, a variable charge acts as a proxy for use of capacity and incentivises efficient use of network resources. A variable component based on consumption is important for promoting dynamic efficiency[10]. The comparison of ADMD to CPD at Table 2, page 14 above illustrates which load groups are deriving the capacity upgrades on our network.
A ratio of 50:50 recognises our cost structures.	Recovering less than 50% of costs through fixed charges risks significant under recovery of our costs.	The majority of our costs are fixed i.e., in the short-term our costs do not change if consumers consume less or more energy on our network.

[9] Demand side management is the intention change in consumer demand for energy via incentives, including financial incentives (i.e., pricing) and education. The goal of demand side management is to encourage the consumer to use less energy during peak hours, or to move the time of energy use to off-peak times such as night time and weekends.

[10] Dynamic efficiency exists where there is an appropriate balance between short run concerns (i.e., static efficiency) and long run concerns (i.e., focusing on encouraging research and development).

Advantage realised	Disadvantage avoided	Discussion
A ratio of 50:50 appropriately balances revenue protection and growth.	50% fixed component reduces the volume risk inherently present in the DPP Determination.	The Commerce Commission requires that we manage our own volume risk when setting prices. A higher variable charge will mean that a greater proportion of revenue is exposed to consumption trends. A higher fixed charge will capture connections growth and protect against fluctuations in volumes.
High proportion of fixed costs to non-standard consumers mitigates the risk of stranded assets	Our larger connections carry stranding risk as these assets are HV assets that are not used by the majority of consumers on our network.	It is appropriate to set a higher fixed charge based on capacity to non-standard consumers so as to ensure revenues align with the original investment decisions regarding the connection of those consumers.

The variable component is further split into day and night

We split our charges with lower night rates to give incentives for shifting load into off–peak periods. Where a consumer has a TOU meter or day/night meters the actual usage is applied. Where a consumer has standard metering consumption is split 70:30 under the assumption that day time consumption is greater than night time consumption.

Fixed daily charges

Fixed daily charges are calculated by dividing each load group's respective revenue requirement by the number of ICP's. Assessed demand and TOU load groups also have a fixed charge based on the installed capacity at their connection site

Impact of Low Fixed Charge Regulations

We calculated tariffs for the LOW load groups using a four step process.

1. The sum of required revenue for LOW and 015 load groups is kept constant.
2. The revenue from fixed daily charges is subtracted from both groups.
3. The remaining variable return is divided by consumption to calculate variable tariffs.
4. A goal seek is applied which determines LOW revenues sufficient to ensure the difference in LOW and 015 annual charges is nil at a level of 9,000 kWh consumption.

Changes in line charges

The median price increase in 2015/16 is 1% when compared to the 2014/15 prices.

Our 2015/16 prices reflect the changes made to the price path under the DPP Determination as set by the Commerce Commission in November 2014.

Of greatest impact to our 2015/16 prices were the:

i) removal of the cost recovery of transmission charges from the weighted average price cap

ii) inclusion of revenue forgone from the first regulatory control period (i.e., 1 April 2010 to 31 March 2015) in pass-through costs.

Our lines charges (i.e., distribution and transmission combined, and excluding metering) effective 1 April 2015 by load group are listed at Table 6. A copy of the 2015/16 and 2014/15 pricing schedules are included at Attachment A and B of this pricing methodology.

Day—is between 7am and 11pm and nigh—is between 11pm and 7am.

Table 6: Alpine Energy lines charges effective as at 1 April 2015

Load Group	Line Charges (excl GST)			
	Fixed ($ p.a.)	Variable Day (c/kWh)	Variable Night (c/kWh)	Demand ($/kW)
LOWHCA	$54.75	$0.0933	$0.0483	
LOWLCA	$54.75	$0.0867	$0.0417	
LOWUHCA	$54.75	$0.1199	$0.0748	
LOWULCA	$54.75	$0.1133	$0.0682	
015HCA	$356.48	$0.0598	$0.0147	
015LCA	$297.20	$0.0598	$0.0147	
015UHCA	$595.73	$0.0598	$0.0147	
015ULCA	$536.45	$0.0598	$0.0147	
360HCA	$1,457.16	$0.0598	$0.0147	
360LCA	$1,215.81	$0.0598	$0.0147	
360UHCA	$1,696.40	$0.0598	$0.0147	
360ULCA	$1,455.06	$0.0598	$0.0147	
ASSHCA	$230.18	$0.0598	$0.0147	$61.40
ASSLCA	$186.76	$0.0598	$0.0147	$57.28
TOU400HCA	$147.74	$0.0212	$0.0048	$146.90
TOU400LCA	$137.23	$0.0212	$0.0048	$133.35
TOU11HCA	$153.12	$0.0212	$0.0048	$127.76
TOU11LCA	$126.90	$0.0212	$0.0048	$121.12

Note: line charges are the combination of distribution and transmission pricing components and are GST exclusive.

7. What are capital contributions

In addition to the line charge revenue that we receive from our consumers we also receive capital contributions from any consumer that require to be connected to our network or need upgrades to their existing connection[11]. In 2013/14 we received $5.1 million in capital contributions. We have forecast to collect $2.4 million in capital contributions for 2014/15.

These capital contributions cover the cost of the work carried out less rebates. This means that, as a general rule, there are no remaining costs to be recovered through line charges. Without a capital contribution these extensions or upgrades would be uneconomic under standard line charges.

A copy of our *New Connections and Extensions Policy* can be found on our website[12].

8. Distributed generation on our network

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

Connected to our network are approximately:

- 99 small distributed generators with less than 10kW and a combined capacity of 0.3 MW that are installed at residential or small business premises
- two distribution generators that are greater than 10kW[13].

These 101 distributed generators total some 34 MW of distributed generation that can flow through our network at any given time.

Fees payable by distributed generators to us are set by the Electricity Authority under the Code.[14] We do not currently 'pay', nor '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 (photo voltaic cells), wind, water (hydroelectric) or fossil fuels such as diesel or natural gas that have energy that is 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[15]. This is an alternative to paying Avoided Cost of Transmission (ACOT) benefits.

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[11] Costs of upgrades to an existing connection can be shared where there are network benefits to the upgrade. Where the upgrade to the sole benefit of the consumer the consumer must pay in entirety for that upgrade.

[12] http://www.alpineenergy.co.nz/our-network

[13] These are a solar panel installation at 15 kW and one hydro installation at 7 MW.

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

[15] In accordance with the Code a connection fee and inspection and living fees do apply.

We do not pay ACOT benefits to most distributed generators as most of them only make a very small contribution to avoiding transmission costs and the transmission costs they do avoid cannot be measured reliability. However a small number of distributed generations do receive an ACOT payment from us and this is determined on a contractual 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 on our website.[16]

9. Calculation of 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 ICP reported 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.[17]

The loss percentage reported under the information disclosure requirements for the year ended 31 March 2014 was 4.8% (or 1.048).

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 transformer losses. Dedicated 33kV line, which provides N-1 security to meet reliability of supply requirements, result in effective losses of less than 2% for loads around 15MW.

10. Overview of our consumer survey

In March 2014 we conducted a 'mass market' consumer survey of approximately 500 consumers randomly from our seven GXP supply areas. We received 275 completed responses in regard to perceptions around supply reliability, inconvenience caused by interruptions, community disruption and price.

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

[17] 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.

Most surveyed consumers believe that their electricity supply reliability is similar to what it has been over the last few years, with about 13% believing that supply reliability has improved and only 7% believing that supply reliability has deteriorated.

From the consumer survey, we also asked about the influence of the 2013 storms.

Road closures and building collapses as a result of the 2013 storms were few, with 68% of surveyed consumers reporting no damage. About 65% of surveyed consumers experienced no inconvenience from electricity supply interruptions resulting from the storms, with a further 27% experiencing some personal inconvenience.

When asked how much extra they might be prepared to pay, about 81% of surveyed consumers indicated that they were not willing to pay any additional line charges to reduce the risk of prolonged supply interruptions due to storms.

Except for the duration of supply interruptions during the 2013 storms, the survey results appear homogeneous and do not reveal any particular market segments as experiencing interruptions or expressing preferences that are significantly different to the total results.

11. The rollout of smart meters on our network

We are currently rolling out smart meters across our network. These meters give real time information about consumers' usage. Once the rollout is complete, real time information on all load groups' usage will be available.

Our current line charges do not reflect the information that will be available after the roll-out is complete. We intend to consider how our lines charges might be structured in a way that anticipates and enables us to use this available information.

12. How we align with the pricing principles

As an electricity distribution business we must meet a number of regulatory requirements. While the Commission sets the levels of revenue that we can earn in any given year, it is the Electricity Authority that influences the approach that we take when we set our lines charges.

Please contact us

We welcome questions about our line charge pricing methodology. Questions can be forwarded to:

Sara Carter
Regulatory and Pricing Manager
Alpine Energy Limited
03 6874 306
sara.carter@alpineenergy.co.nz

Appendix A—How we align with the 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 (equal to or greater than incremental costs, and less than or equal to standalone costs), except where subsidies arise from compliance with legislation and/or other regulation	Cross subsidies occur where prices charged to a consumer or consumer group do not recover the incremental costs of providing the line service. As we have a large proportion of assets being fixed costs that are shared by various load groups, the incremental costs of serving a consumer are very small. This means that cross subsidies are very unlikely to occur. We have interpreted incremental cost as a short-run cost measure that recognises the cost of providing an additional unit of electricity to each consumer group. We have interpreted standalone cost as the lowest cost alternative of serving each consumer group. Our standalone costs are \$0.5072/kWh and our long–run incremental costs (LRIC) are \$0.0303/kWh. Table 9 shows that the forecast revenue is greater than the incremental cost and less than the standalone cost for each load group; demonstrating that our prices are subsidy free.
(ii) having regard, to the extent practicable, to the level of available service capacity	Our prices encourage consumers to shift load from peak to off–peak through our variable night and day charges and by charging for uncontrollable load. We also encourage efficient use of available service capacity by using charges that increase with demand.

Table 9: variable distribution price per load group

Load Group	\$/kWh
LOWLCA	\$0.1003
LOWUHCA	\$0.0982
LOWULCA	\$0.0890
015HCA	\$0.1835
015LCA	\$0.0571
015UHCA	\$0.0623
015ULCA	\$0.0693
360HCA	\$0.0928
360LCA	\$0.1039
360UHCA	\$0.0783
360ULCA	\$0.0916
ASSHCA	\$0.0802
ASSLCA	\$0.0723
TOU400HCA	\$0.0582
TOU400LCA	\$0.0303
TOU11HCA	\$0.0363
TOU11LCA	\$0.0319

<table>
<tr><th>Pricing Principles</th><th>Alpine Energy Limited’s Alignment to the Principles</th></tr>
<tr><td>(iii) signalling, to the extent practicable, the impact of additional usage on future investment costs</td><td>It is demand during peak periods that drives future investment in capacity. Our prices encourage consumers to reduce their peak consumption by using capacity and demand based pricing. Charges that increase with demand signal to consumers the cost of investment in capacity and therefore defer future network investment.

Customers that require new or upgraded power supply are charged capital contributions in addition to lines charge revenue which highlights some of the costs associated with future investment.</td></tr>
<tr><td colspan="2">(b) Where prices based on ‘efficient’ incremental costs would under–recover allowed revenues, the shortfall should be made up by setting prices in a manner that has regard to consumers’ demand responsiveness, to the extent practicable.</td></tr>
<tr><td colspan="2">This principle encourages distributors to direct the recovery of network fixed costs towards those consumers who are less price-responsive and will therefore reduce their demand by the lowest amount. This means that we must consider how different consumer groups might respond to changes in price.

However, considering how different consumer groups might respond to change in price is very difficult for us to determine as we hold limited information about price elasticity of demand as information at the consumer level is held by retailers. Therefore we apply this principle at a principle-based level by measuring the impact of changes on price on the ‘average consumer’ when we set prices for standard customers.</td></tr>
<tr><td colspan="2">(c) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:</td></tr>
<tr><td>(i) discourage uneconomic bypass</td><td>This principle aims to ensure that prices that enable the recovery of fixed network costs do not drive any consumers to an alternative solution that increases total costs to all parties involved (i.e., uneconomic bypass).

We are of the view that uneconomic bypass is not a major concern on our network as most consumers will have high standalone costs. Large industrial consumers that have a choice over alternative locations and have reasonable negotiating power are the greatest risk of bypass.

We manage this risk through our non–standard contracts which facilitates negotiation with consumers who believe their standalone cost is lower than price in order to avoid exceeding the standalone cost.</td></tr>
</table>

Pricing Principles	Alpine Energy Limited's Alignment to the Principles
(ii) allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangements for services	This principle reflects the regulators concern that monopoly service providers have few incentives to actively engage with their consumers. Consumer engagement should allow prices to more closely resemble 'market–like' transactions because consumers have the ability to communicate their expectations and preferences to the regulated firm. We align with this principle through our annual consumer surveys and through our engagement with non–standard consumers. The surveys helps us to understand price quality trade-offs from the consumer's perspective. That is, whether consumers are willing to pay more for a higher quality service and also what the impact of specific events (e.g., severe weather) had on them. As a result of our interactions with our non-standard consumers, we understand the preferences of these consumers well. The non–standard contracts are also negotiated to reflect price/quality trade–offs.
(iii) where network economics warrant, and to the extent practicable, encourage investment in transmission and distribution alternatives (e.g., distributed generation or demand response) and technology innovation	We pay Avoided Cost of Transmission (ACOT) benefits to a small number of large distributed generators on a contractual basis. This is to encourage such generators to generate during peak transmission periods. However, we do not pay ACOT to small distributed generators as they make a very small contribution to avoiding transmission costs. Instead we allow generators to use our distribution network without incurring network charges.
(d) Development of prices should be transparent, promote price stability and certainty for stakeholders, and changes to prices should have regard to the impact on stakeholders	
We are of the view that our line charges are understandable for stakeholders (for example, consumers, retailers, shareholders, and us). Our line charges have been developed in a manner that intends to promote certainty and price stability. When we have had to increase line charges 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 line charges will be stable and will not shift significantly over time. Increases to our lines charges have been, and will continue to be, consistent with the limits placed on us under the DPP determination by the Commerce Commission.	

Pricing Principles	Alpine Energy Limited's Alignment to the Principles
(e) Development of prices should have regard to the impact of transaction costs on retailers, consumers and other stakeholders and should be economically equivalent across retailers	
This principle encourages EBDs to recognise the costs that they can impose on retailers, consumers and other stakeholders and to find ways to minimise those costs. We are managing the transaction costs on retailers by discussing pricing with other EBD's in the lower South Island in order to help with standardisation of tariffs. If tariffs are overly complex this creates costs for retailers and consumers. We are of the view that our tariffs are not overly complex and should not impose high transaction costs on retailers and consumers. We also believe that our pricing methodologies maintain economic equivalence across retailers.	

Attachment A—Prices effective as at 1 April 2015

Alpine Energy Limited Pricing Schedule 1 April 2015		Distribution Fixed per annum	Distribution Variable Day per kWh	Distribution Variable Night per kWh	Distribution Demand per kW per annum	Transmission Fixed per annum	Transmission Variable Day per kWh	Transmission Variable Night per kWh	Transmission Demand per kW per annum	Metering Fixed per annum	Number of Connection Points as at 31/12/2014
LOWHCA	Low Charge	$54.75	$0.0762	$0.0447	$0.00	$0.00	$0.0171	$0.0035	$0.00	$77.57	1,200
LOWLCA	Low Charge	$54.75	$0.0697	$0.0382	$0.00	$0.00	$0.0171	$0.0035	$0.00	$73.87	7,090
LOWUHCA	Low Uncontrolled	$54.75	$0.0762	$0.0447	$0.00	$0.00	$0.0437	$0.0301	$0.00	$77.57	8
LOWULCA	Low Uncontrolled	$54.75	$0.0697	$0.0382	$0.00	$0.00	$0.0437	$0.0301	$0.00	$73.87	16
015HCA	015	$356.48	$0.0427	$0.0112	$0.00	$0.00	$0.0171	$0.0035	$0.00	$77.57	6,091
015LCA	015	$297.20	$0.0427	$0.0112	$0.00	$0.00	$0.0171	$0.0035	$0.00	$73.87	14,328
015UHCA	015 Uncontrolled	$356.48	$0.0427	$0.0112	$0.00	$239.24	$0.0171	$0.0035	$0.00	$77.57	36
015ULCA	015 Uncontrolled	$297.20	$0.0427	$0.0112	$0.00	$239.24	$0.0171	$0.0035	$0.00	$73.87	53
360HCA	360	$1,457.16	$0.0427	$0.0112	$0.00	$0.00	$0.0171	$0.0035	$0.00	$118.92	445
360LCA	360	$1,215.81	$0.0427	$0.0112	$0.00	$0.00	$0.0171	$0.0035	$0.00	$113.25	689
360UHCA	360 Uncontrolled	$1,457.16	$0.0427	$0.0112	$0.00	$239.24	$0.0171	$0.0035	$0.00	$118.92	14
360ULCA	360 Uncontrolled	$1,215.81	$0.0427	$0.0112	$0.00	$239.24	$0.0171	$0.0035	$0.00	$113.25	8
ASSHCA	Assessed	$230.18	$0.0427	$0.0112	$26.78	$0.00	$0.0171	$0.0035	$34.62	$118.92	1,173
ASSLCA	Assessed	$186.76	$0.0427	$0.0112	$23.33	$0.00	$0.0171	$0.0035	$33.95	$113.25	356
TOU400HCA	TOU 400V	$147.74	$0.0184	$0.0032	$82.24	$0.00	$0.0028	$0.0017	$64.65	$284.95	35
TOU400LCA	TOU 400V	$137.23	$0.0184	$0.0032	$68.70	$0.00	$0.0028	$0.0017	$64.65	$271.39	103
TOU11HCA	TOU 11kV	$153.12	$0.0184	$0.0032	$63.11	$0.00	$0.0028	$0.0017	$64.65	$1,139.79	6
TOU11LCA	TOU 11kV	$126.90	$0.0184	$0.0032	$56.46	$0.00	$0.0028	$0.0017	$64.65	$1,085.51	4

Notes:

Fixed Charges accrue daily at the rate of 1/365th of the annual amount. The Fixed Transmission charge for sites in the 015UHCA, 015ULCA, 360UHCA and 360ULCA load groups is a special charge for the provision of electric water heating that cannot be controlled by Alpine Energy via a ripple relay.

Variable Charges are made up of day unit charges which are levied in respect of all units used between 7am and 11pm and night unit charges which are levied in respect of the period 11pm to 7am. Charges are based on metering at the Grid Exit Points supplying the network with a reduction for the declared network loss level to emulate usage metered on site. The additional distribution charge of 3.35 cents/kWh for day and night usage in the LOWHCA and LOWUHCA load groups, and 2.70 cents/kWh for day and night usage in the LOWLCA and LOWULCA load groups is charged based on usage advised by electricity retailers. The additional variable transmission charge of 2.66 cents/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.

Demand Charges only apply to sites with a demand (kW) charge. The demand level at these sites is assessed and set by us and is available on request. The charge accrues daily at the rate of 1/365th of the annual amount.

Metering Charges are levied for all sites where we are the metering equipment provider (including CTs and VTs).

All Charges are GST exclusive. GST is payable in addition to the charges. Additional terms and conditions detailed in our Use of System Agreement and Memorandum of Understanding may also apply.

 Pricing Methodology 2015

Attachment B—Prices effective as at 1 April 2014

Alpine Energy Limited Pricing Schedule 1 April 2014		Distribution				Transmission				Metering	Number of
		Fixed *per annum*	**Variable Day** *per kWh*	**Variable Night** *per kWh*	**Demand** *per kW per annum*	**Fixed** *per annum*	**Variable Day** *per kWh*	**Variable Night** *per kWh*	**Demand** *per kW per annum*	**Fixed** *per annum*	**Connection Points** *as at 19/09/2013*
LOWHCA	Low Charge	$54.75	$0.0725	$0.0451	$0.00	$0.00	$0.0223	$0.0046	$0.00	$76.79	974
LOWLCA	Low Charge	$54.75	$0.0659	$0.0385	$0.00	$0.00	$0.0223	$0.0046	$0.00	$73.13	6,414
LOWUHCA	Low Uncontrolled	$54.75	$0.0725	$0.0451	$0.00	$0.00	$0.0571	$0.0394	$0.00	$76.79	6
LOWULCA	Low Uncontrolled	$54.75	$0.0659	$0.0385	$0.00	$0.00	$0.0571	$0.0394	$0.00	$73.13	14
015HCA	015	$379.48	$0.0375	$0.0101	$0.00	$0.00	$0.0223	$0.0046	$0.00	$76.79	6,220
015LCA	015	$319.40	$0.0375	$0.0101	$0.00	$0.00	$0.0223	$0.0046	$0.00	$73.13	14,910
015UHCA	015 Uncontrolled	$379.48	$0.0375	$0.0101	$0.00	$312.21	$0.0223	$0.0046	$0.00	$76.79	30
015ULCA	015 Uncontrolled	$319.40	$0.0375	$0.0101	$0.00	$312.21	$0.0223	$0.0046	$0.00	$73.13	49
360HCA	360	$1,387.70	$0.0375	$0.0101	$0.00	$0.00	$0.0223	$0.0046	$0.00	$117.73	404
360LCA	360	$1,187.23	$0.0375	$0.0101	$0.00	$0.00	$0.0223	$0.0046	$0.00	$112.12	660
360UHCA	360 Uncontrolled	$1,387.70	$0.0375	$0.0101	$0.00	$312.21	$0.0223	$0.0046	$0.00	$117.73	13
360ULCA	360 Uncontrolled	$1,187.23	$0.0375	$0.0101	$0.00	$312.21	$0.0223	$0.0046	$0.00	$112.12	7
ASSHCA	Assessed	$126.31	$0.0375	$0.0101	$13.71	$0.00	$0.0223	$0.0046	$45.18	$117.73	1,096
ASSLCA	Assessed	$107.85	$0.0375	$0.0101	$11.71	$0.00	$0.0223	$0.0046	$44.30	$112.12	346
TOU400HCA	TOU 400V	$126.38	$0.0144	$0.0022	$66.40	$0.00	$0.0036	$0.0022	$84.37	$282.10	32
TOU400LCA	TOU 400V	$108.73	$0.0144	$0.0022	$57.13	$0.00	$0.0036	$0.0022	$84.37	$268.67	103
TOU11HCA	TOU 11kV	$126.38	$0.0144	$0.0022	$49.80	$0.00	$0.0036	$0.0022	$84.37	$1,128.38	6
TOU11LCA	TOU 11kV	$108.73	$0.0144	$0.0022	$42.85	$0.00	$0.0036	$0.0022	$84.37	$1,074.65	4

Notes:

Fixed Charges accrue daily at the rate of 1/365th of the annual amount. The Fixed Transmission charge for sites in the 015UHCA, 015ULCA, 360UHCA and 360ULCA load groups is a special charge for the provision of electric water heating that cannot be controlled by Alpine Energy via a ripple relay.

Variable Charges are made up of day unit charges which are levied in respect of all units used between 7am and 11pm and night unit charges which are levied in respect of the period 11pm to 7am. Charges are based on metering at the Grid Exit Points supplying the network with a reduction for the declared network loss level to emulate usage metered on site. The additional distribution charge of 3.50 cents/kWh for day and night usage in the LOWHCA and LOWUHCA load groups, and 2.84 cents/kWh for day and night usage in the LOWLCA and LOWULCA load groups is charged based on usage advised by electricity retailers. The additional variable transmission charge of 3.48 cents/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.

Demand Charges only apply to sites with a demand (kW) charge. The demand level at these sites is assessed and set by us and is available on request. The charge accrues daily at the rate of 1/365th of the annual amount.

Metering Charges are levied for all sites where we are the metering equipment provider (including CTs and VTs).

All Charges are GST exclusive. GST is payable in addition to the charges. Additional terms and conditions detailed in our Use of System Agreement and Memorandum of Understanding may also apply.