

Methodology for deriving delivery prices

For prices applying from 1 April 2019

Issued 22 February 2019

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Glossary of abbreviations

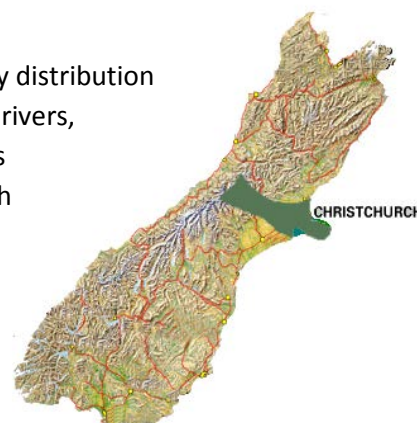
The following abbreviations are used in this document:

- **ADMD**, for *after diversity maximum demand*. Customers¹ within each connection category use electricity at different times – a high load from one customer is often offset by others with low load – and we assess the maximum of this “diversified” loading. For distribution assessments we consider the ADMD at times when the local network supplying the load is peaking, for transmission assessments we consider the ADMD of each category at times when the overall network is peaking.
- **ΣAMD**, for *sum of anytime maximum demands*. This is the sum of the individual peaks (occurring at different times) of the connections in a category.
- **CPP**, for *customised price-quality path*. An alternative to the default form of price regulation administered by the Commerce Commission. Applied to Orion from April 2014 to March 2019.
- **DPP**, for *default price-quality path*. This is the form of price regulation that applied to Orion up to 31 March 2014 and applies from 1 April 2019.
- **IRIS**, for *Incremental Rolling Incentive Scheme*.
- **LRAIC**, for *long run average incremental cost*. See the definition and discussion in section 7 and the derivation in Appendix E.
- **ODRC**, for *optimised depreciated replacement cost*. This is a measure of the depreciated value of assets, based on replicating the network, using modern equivalent assets and an efficient design.
- **ODV**, for *optimised deprival value*. This is the total value of assets that allows the network to operate in an efficient, long term commercially sustainable way.
- **RIV**, for *regulatory investment value*. This represents the indexed depreciated regulatory value of assets (the regulatory asset base, or RAB) with deferred tax adjustments.
- **TPM**, for *transmission pricing methodology*. This is the methodology that Transpower follows in setting the prices and charges applicable to its customers.
- **VOLL**, for *value of lost load*. This is the amount that we assess customers in each connection category are willing to pay (on average) to avoid a power cut.
- **WACC**, for *weighted average cost of capital*. As determined by the Commerce Commission for setting allowable revenue and against which Orion’s actual returns are compared and assessed.

¹ In this document we generally use the term “customer” to refer to end consumers. Some references to external documents use the term “consumer”, for example the references to the distribution pricing principles. We consider the terms to be interchangeable.

1 Introduction

Orion New Zealand Limited (Orion) owns and operates the electricity distribution network in central Canterbury between the Waimakariri and Rakaia rivers, and from the Canterbury coast to Arthur's Pass. Our network covers 8,000 square kilometres of diverse geography, including Christchurch city, Banks Peninsula, farming communities and high country regions. We receive electricity from Transpower's national grid at 7 different locations² and we distribute this electricity to more than 200,000 homes and businesses.



New Zealand's South Island

Our service covers the delivery of electricity only - we do not buy and sell electricity, we simply deliver it to the customers of electricity retailers that operate in our area. We charge electricity retailers on a wholesale basis for this delivery service. Electricity retailers, in turn, include this cost in their retail electricity prices - our delivery charges typically amount to around 40% of a household's electricity bill.

Our network is entirely within the boundaries of the two local councils that own Orion, Christchurch City Council (which owns 89.3%) and Selwyn District Council (which owns 10.7%).

Our network is a natural monopoly: due to economies of scale a competitor could not profitably duplicate our network. As a result, we are not exposed to the competitive pressures that drive improved efficiencies and service levels in other markets. As a surrogate for these competitive pressures, the government has developed regulations for electricity network owners under the Commerce Act 1986 (the Act). The Act is administered by the Commerce Commission.

The Act requires Orion to:

- limit delivery price increases, while maintaining quality of supply; and
- disclose certain information about our business, including this pricing methodology statement.

The purpose of information disclosure is to promote efficient operation of electricity distribution businesses by ensuring that electricity distributors make publicly available reliable and timely information about the operation and behaviour of their businesses. This helps to inform a wide range of people about such factors as profits, costs, asset values, price, quality, security and reliability. It therefore supports assessment of whether the purpose of the Act is being met.

² A small (but growing) amount of energy also enters the network from connections that have generation capability, such as solar panels.

2 Pricing principles, objectives and strategy

We aim to set prices that provide sufficient revenue to cover all our costs, including pass through and recoverable costs (primarily transmission costs) and our cost of capital, while seeking to comply with the regulations. The structure of our pricing aims to reflect the economic costs of providing our delivery service. With this approach, customers can make efficient decisions about which form of energy to use and when to use it, which contributes to economic welfare.

Recognising these high level objectives, the following considerations influence our pricing. There is often a trade-off between these various considerations.

2.1 Economic considerations

We aim to ensure that our pricing is economically efficient, which means that:

- customers choosing to use our network should face the appropriate cost of that decision and be incentivised to weigh up the value of the service and the cost of alternatives, and consequently
- investments in our network over time will be at an appropriate level and in the interest of customers.

The key economic input to our pricing is the long run average incremental cost (LRAIC) of investment in our network on the basis that, if customers are prepared to pay prices that reflect LRAIC, then further investment in our network is economically efficient. We apply this concept consistently in our pricing across the various groups, and in particular via the ‘peak’ components.

Our derivation and application of LRAIC is described in more detail in section 7 and Appendix E.

2.2 Even-handedness and practical considerations

Orion takes into account the need for even-handedness and practicality in determining customer groupings, cost allocations and the structure of our pricing. Specifically we:

- apply price averaging over large groups of connections, because it is generally not practical to single out individual connections for cost-specific delivery pricing. (However, where it is practical we do allocate assets and associated costs only to the connections that use them.)
- recognise that all customers should share in the benefits of greater utilisation of shared assets (and other enhanced economies of scale)
- recognise that customers change their demand behaviour only over relatively long periods of time and it is important that we provide compelling and consistent pricing incentives aimed at maximising the efficient utilisation of our assets (for example, low night time prices that encourage off-peak usage)
- seek to make our price signals effective by balancing strong price signals with easily understood application and measurement
- treat connections with similar electrical attributes consistently
- set prices that are the same for all retailers, providing a “level playing field” to promote retail competition.

2.3 Return on investment

We operate our business in a commercial environment and, to ensure continued and appropriate investment in our network (including for the long term benefit of customers), we aim to meet the expectations of our shareholders – particularly in relation to providing commercially realistic returns on the value of their investment.

However, the most significant factor currently influencing our return on investment is the default price-quality path (DPP) determined for Orion by the Commerce Commission (the “Commission”). The Commission’s regulation is described in more detail in section 2.6 below.

The Commission publishes estimates of WACC from time to time. In this document we estimate our return with respect to the most recent Commission estimate. However, it is important to note that it is our prices that are regulated, not our return on investment. Our actual returns over any year will differ from WACC due to:

- timing: our 2019/20 prices are largely a rollover of our 2018/19 CPP prices, and as such are not closely related to our 2019/20 costs,
- differences between assumed and actual growth.

2.4 Regulatory considerations

The principal regulatory requirement that we seek to comply with is the price-quality path set for us by the Commission as described above.

We also consider other regulatory and policy requirements, and in particular:

- the information disclosure requirements (as they relate to pricing) promulgated by the Commission in October 2012 (a cross-referencing of this methodology to the information disclosure requirements is included in Appendix B),
- the distribution pricing principles and associated guidelines administered by the Electricity Authority (the “Authority”). Our assessment of Orion’s alignment with these is included in Appendix B,
- the Authority’s views on the need for distributors to develop and publish plans for how they intend to implement ‘service-based’ and ‘cost-reflective’ pricing (we have set out our current plans for possible future pricing changes in appendix C),
- the Electricity Industry Act provision relating to the protection of rural customers which, as we interpret it, indicates that rural prices should not be different to urban prices³,
- the Low Fixed Charge regulations that require that we provide pricing options with low fixed charges for residential customers, and
- the regulations relating to the connection of distributed generation.

We note that both key pieces of governing legislation that relate to pricing - the Commerce Act 1986 and the Electricity Industry Act 2010 - are aimed at ensuring the long term interests of consumers are met. That is consistent with Orion’s objectives.

³ Electricity Industry Act 2010, section 113 (1) (c).

Our pricing strategy (see section 2.8 below) encapsulates our pricing principles and objectives as set out in this section and should be read in conjunction with them.

2.5 Changes to the methodology

There are some changes to Orion's pricing methodology since the last methodology was published in February 2018:

- We are introducing a 15 cents per day fixed charge for all general connections from 1 April 2019. This change is an initial step in reducing the inefficient incentive to avoid or reduce usage volumes at non-peak times.
- We are also reducing the weekday volume prices (with a corresponding increase in night and weekend volume prices) to further mitigate the inefficient pricing incentive to avoid or reduce weekday usage at non-peak times.
- We have adjusted the boundary between our major customer and general connection price categories, broadening the range where customers can elect which category to belong to. At the same time we have adjusted major customer pricing to better align with costs at the smaller end of the category. This change reduces the price shock associated with changing category as a customer's demand changes.
- We are also making some technical changes to the way prices are calculated and presented to reflect the different approach to compliance assessment under a DPP as compared with our CPP. This is mainly in the area of pass-through and recoverable costs.

2.6 Transition from customised price-quality path

The earthquakes in the Canterbury region in 2010 and 2011 had a significant impact on Orion's business.

From early 2012 we worked on a customised price-quality path (CPP) proposal to address the financial and reliability impact of the earthquakes. This was submitted to the Commerce Commission in February 2013. The Commission then considered our proposal and issued a final determination on 29 November 2013. This determination provided for an initial more significant increase which we applied from 1 April 2014, followed by annual increases at 1% above the rate of inflation for the following four years.

In October 2016 the Commission determined how Orion should return to price quality control under the default price-quality path (DPP), and our prices to apply from 1 April 2019 have been set according to that determination.

2.7 Customer consultation

The information disclosure requirements set out in the October 2012 Commission determination include a requirement regarding the extent to which the views of customers in terms of price and quality have been sought and reflected in the price-setting process.⁴

⁴ Commerce Commission, Decision NZCC 22: Electricity Distribution Information Disclosure Determination 2012, 2.4.1 (4). The Determination uses the term consumer rather than customer.

In terms of price structure, we undertake consultation when we propose any changes to our pricing. The last such consultation occurred in September and October 2018. In this update the views expressed by stakeholders broadly supported our changes and we implemented a range of adjustments described in section 2.5 above.

This consultation also sought views on our longer term pricing reform, and has informed our direction for possible future pricing changes as set out in appendix C.

We have also consulted with customers, by way of focus groups, on the challenges and re-distributional consequences of having prices based largely on volumes when supply costs are fixed, and particularly in the context of the potential for some customers to invest in technologies such as solar PV. This consultation has informed our decision to implement the fixed charge for general connections.

In addition we have established a customer advisory panel to assist us in, amongst other things, considering price quality trade-offs inherent in our network investment and operation.

More generally, we are always open to comments on our pricing from any party, and in particular we present our prices to retailers each year as proposed prices that they are able to comment on.

Specifically in terms of the price-quality trade off and reflecting this in price setting, for the most part we have *not* sought the views of customers, for the following reasons:

- in our view, consultation is relevant as part of the asset management plan (AMP) process and, in Orion's case the 2012 - 2013 CPP process. These processes allow consideration of meaningful trade-offs between our investment and asset management decisions (which are our key cost drivers) and the associated future quality of the delivery service. To the extent that the consultation impacts on our investment this will, over time, be reflected in changes in the real prices that customers pay, and the quality of supply they receive,
- the Commission's final decision on our CPP reflected consultation carried out by both Orion and the Commission. It clearly links planned operating and capital expenditure - and therefore our prices - to our quality targets for the CPP period, and our prices for 2019/20 are largely a rollover of our CPP prices,
- further consultation as part of the price-setting process would involve considerable duplication of the AMP process, and
- the Commission consults on the framework of price-quality regulation on an ongoing basis. All consumers and their representatives have an opportunity to participate in that consultation.

2.8 Pricing strategy

Our high level pricing strategy was formally approved by the Orion board at its meeting on 5 December 2018. The strategy is as follows⁵:

Our delivery pricing strategy

We aim to set our delivery prices to provide sufficient revenue to recover our prudent and efficient costs, including our cost of capital. We also aim to comply with the price control regulations.

We aim to reflect the long term economic costs of providing consumers with the quality of delivery service that they require. Cost recovery is fundamental to retaining our incentives to invest in our network in the long term interests of consumers. In structuring and setting our prices we take a medium to long term view, and we consider economic efficiency, equity and practicality. We seek to ensure that our pricing is economically efficient, which means that customers who use our network face the appropriate cost of that use, and are incentivised to weigh up the value of our delivery service and the alternatives. Cost reflective prices should help to ensure that our investments in our network over time will be at an appropriate level.

In determining customer groupings, cost allocation and the structure of our pricing we:

- apply price averaging over large numbers of connections, because it is generally not practicable to single out individual connections for cost-reflective delivery pricing. Where it is practicable to do so we allocate assets and costs to the specific connection categories that use them,
- recognise that all consumers should share in the benefits of greater utilisation of shared assets and economies of scale,
- recognise that consumers generally change their demand behaviour over relatively long periods of time and it is important that we provide compelling and consistent pricing incentives aimed at maximising the efficient utilisation of our assets,
- seek to make our prices effective, by balancing strong price signals with simple application and measurement,
- set prices that are the same for all retailers, providing a “level playing field” to promote retail competition.

Key considerations relating to our pricing over the next five years include:

- preserving incentives for managed water heating load,
- the impact of changing use of the network due to emerging technologies such as distributed generation, battery storage and electric vehicles,
- the Commerce Commission’s approach to the 1 April 2020 DPP reset and in particular the form of control as we move from a weighted average price cap to a revenue cap,
- the recommendations of the government’s Electricity Price Review, in particular its recommendations regarding the low fixed charge regulations,
- the Electricity Authority’s:
 - continuing review of Transpower’s transmission pricing methodology (TPM),
 - recent publication “It’s time to reform distribution pricing”,
 - consultation on the pricing principles and introduction of a rating system for EDB pricing approaches.

The way we implement our pricing strategy is updated and publicly disclosed in our pricing methodology document. We usually change our delivery prices on 1 April each year. We review and update this pricing strategy at least annually.

3 Overview of our methodology

3.1 Methodology

Our charges represent the delivery costs of electricity – we contract with Transpower to deliver electricity across the national grid from generation points to our network, and we provide the local network to distribute electricity to each connection.⁶

We refer to Transpower's service as *transmission*, our service as *distribution*, and the combined transmission and distribution service as a *delivery* service. We set delivery prices to recover the costs of the combined transmission and distribution services.

In summary, our pricing approach is to:

- establish connection categories based on connections that have similar load characteristics, use specific sets of assets or give rise to a similar set of costs
- establish total costs, including:
 - transmission charges, costs of investments that avoid transmission charges and payments to embedded generators in lieu of transmission charges,
 - regulated recoveries and incentive allowances,
 - regulated pass-through cost allowances,
 - asset depreciation, asset disposal losses and return on capital invested,
 - tax,
 - operations and maintenance costs,
 - administration costs,
 - payments to distributed generators in lieu of distribution costs,
 - payments to irrigators for power factor correction and interruptibility, and
 - the extent to which costs are offset by other (non delivery) revenue, such as advertising and car parking revenue.
- allocate transmission costs to each connection category based on our assessment of each category's use of the transmission system
- allocate regulated allowances to each connection category
- allocate non-asset based distribution costs (distributed generation and administration costs) to each connection category
- assess each connection category's use of network assets and assign the average depreciated value of assets to each connection category
- allocate asset related costs (operations and maintenance, depreciation and return on capital) to each connection category based on the asset value assigned to each category, and the applicable WACC as established by the Commission's Input Methodologies

⁵ Pursuant to section 2.4.4 of the information disclosure determination (IDD), and further to the discussion in section 3.2 below.

⁶ And, to an increasing extent, we deliver electricity produced at customer connections.

- calculate an overall discount that is required to meet the requirements of the Commission’s price-quality path and allocate the discount to each connection category on an equitable basis that minimises any resulting price shock
- estimate the long run average incremental cost (LRAIC) of investment in our network
- establish a cost reflective pricing structure driven by LRAIC and estimate the chargeable quantities for the pricing structure
- using this price structure and quantities, set prices to meet the revenue requirement established by the cost allocation.

For the majority of our connections, we apply a ‘GXP billing’ approach where, in simple terms, charges are based on electricity volumes measured at the few points of injection into the Orion network (principally Transpower grid exit points). Chargeable quantities attributed to each retailer are determined by the wholesale electricity market reconciliation process with adjustments for embedded networks and major customer quantities. This provides a number of administrative efficiencies for Orion which are reflected in our costs.

The use of reconciled quantities also allows us to measure retailer’s demands on the network half-hourly, which enables us to have cost-reflective ‘time-of-use’ and ‘peak’ components in our pricing. Peak demands are measured over the periods when we are managing load because total network demand is high. We signal these periods to support customer choice.

In addition to charges based on these reconciled quantities we are, from 1 April 2019, introducing a 15 cents per day fixed charge for all general connections.

Retailers choose how they present our price signals to customers, and they do so in a variety of ways. Retailers can also manage their costs by leveraging features of the reconciliation process such as profiles and the use of individual customer’s half hourly data from smart meters. Finally, retailers can use their understanding of different customer demand characteristics when modelling our costs.⁷ Our pricing supports innovation by leaving decisions about the relative importance of these factors, and how they might be responded to, to the competitive market.

More detail on how we apply our prices, and in particular on how the chargeable quantities are calculated for each connection category, can be found in our *Pricing policy* document, which is available on our website.

3.2 Pricing

This pricing methodology is primarily focussed on the year ahead – April 2019 to March 2020, and for this year the Commission has decided that our prices from the previous year will roll over, with a CPI adjustment and a deduction for the ‘clawback’ that we are recovering in the CPP period.⁸

⁷ For example, the average delivery cost (for the retailer on a cents per kWh basis) for a customer with solar panels (PV) might be higher than a customer without them, while the average cost for customers that use gas for space heating might be lower than that of customers that do not.

⁸ See “Electricity Distribution Services Default Price-Quality Path Amendment Determination 2016 [2016] NZCC 19”, at <http://www.comcom.govt.nz/dmsdocument/14806>.

This section⁹ comments on anticipated trends in cost drivers and pricing over the next five years.

Pricing for the next five years

From April 2020, our prices will be determined according to the methodology for the 2020 reset that the Commission will establish over the next year. Of particular note is that the form of control will change from a weighted average price cap to a revenue cap.

Separately, we are likely to face changes in transmission costs over the next five years.

- Transpower has signalled small changes in its revenue requirement after 2018/19 through to the end of its 'RCP2' in 2019/20.
- The Authority has, over a number of years, proposed significant changes to the transmission pricing methodology (TPM) which could, if implemented, dramatically change the level and incidence of transmission costs. At this stage we think it unlikely that any TPM changes will take effect before April 2020.

New and emerging technologies

Like most distributors, Orion is seeing a rapid increase in the uptake of photo-voltaic (PV) generation, mostly on houses. The Electricity Authority has highlighted the fact that, while on-site generation can have economic benefits, some electricity customers can end up subsidising others if pricing is distorted. Orion shares this view, in particular that the low fixed charge regulations tend to make the variable components of delivery prices higher than they should be, which means the value of offset consumption (typically 25 to 30 cents per kWh) is much more than the reduction in network costs (which is effectively zero for PV).

The Authority issued a consultation paper in November 2015 on distribution pricing in the context of emerging technologies. The paper challenges the dominant distributor view, shared by Orion, that we are significantly constrained by the low fixed charge regulations. The Authority has followed up with guidance on how it will interpret the regulations particularly with respect to what sort of charges it would see as variable. After considerable discussion with the Authority we have formed the view that the guidelines are unhelpful.

More broadly, the Authority's work has led to it setting out expectations of distributors in implementing more cost reflective and service based pricing. This is discussed more fully in appendix C below.

We are also keeping an eye on developments with batteries and electric vehicles (EVs). Key for us is how people decide when to charge them, and, in the case of batteries, when to discharge them. We believe even very significant EV uptake can be accommodated on our existing network so long as charging occurs at off-peak times (for example overnight). However, if most charging occurs at peak times this could require additional network investment. Also, as EV numbers increase, the coincidence of the commencement of charging (at any time) could present challenges.

⁹ This section is intended to provide the information specified in sections 2.4.4 (1), (2) and (3) of the Commission's information disclosure requirements. Section 2.8 includes the pricing strategy approved by the Orion board.

Changes to pricing strategy

Other than accommodating the changing factors noted above, there have been no changes to our pricing strategy.

4 Connection categories

We have identified situations where groups of customers place significantly different demands on delivery assets, and situations where customers use different sets of those delivery assets. We have established connection categories that reflect these differences to provide a more accurate basis of assigning costs. Our categories are:

- Streetlighting connections
- General connections
- Irrigation connections
- Major customer connections
- Large capacity connections

We determine which category applies to each ICP, and this is reviewed from time to time.

This section describes each of these categories, the rationale for maintaining the category, and the key statistics for the category. The key statistics inform the cost allocations set out in section 6.

4.1 Streetlighting connections

Orion owns and maintains a low voltage network of lines and cables dedicated to the provision of streetlighting (including lighting of some parks and reserves). To a large extent, this network runs alongside our regular low voltage network; it is the fifth wire on our overhead lines and the fifth core in our underground cables. We switch these circuits on at night and off in the mornings, using a combination of light sensors and timers and our ripple signalling system.

To reflect the dedicated use of our lighting network, we maintain a specific category for streetlighting connections. All private and publicly owned dedicated lighting connections supplied from our streetlighting circuit are included within this connection category.¹⁰

Assessed key statistics for streetlighting connections (1 April 2019 to 31 March 2020)	Forecast
Number of chargeable connections	49,513 (average)
Number of ICPs	520 (average)
Energy volume	26,722 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	3,010 kW
– contribution to network-wide summer peak (ADMD)	219 kW
– contribution to local network peak (ADMD)	3,010 kW
– sum of individual connection anytime peaks (ΣAMD)	6,387 kW
Value of lost load (VOLL)	\$15.08 / kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (i.e. with normal distribution losses added).

¹⁰ There is a small but increasing number of streetlights that are not connected to our dedicated streetlighting network and so are not in this category. These instead form part of our general connections category.

4.2 General connections

This category includes all residential connections and most business connections, including a number of sites with half-hour interval metering, but excludes connections that belong to the other connection categories (those in the streetlighting, irrigation, major customer and large capacity connection categories).

General connections make use of all network assets (except lighting circuits) and, given the cost reflectivity of our pricing within the category, we have not identified any reason to separately consider any subset of this category.

Assessed key statistics for general connections (1 April 2019 to 31 March 2020)	Forecast
Number of connections / ICPs	201,095 (average)
Energy volume	2,252,068 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	469,384 kW
– contribution to network-wide summer peak (ADMD)	273,135 kW
– contribution to local network peak (ADMD)	469,384 kW
– sum of individual connection anytime peaks (Σ AMD)	1,967,384 kW
Value of lost load (VOLL)	\$15.74 / kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (i.e. with normal distribution losses added).

4.3 Irrigation connections

We provide a specific irrigation connections category because electrical loads from irrigators are very different to those of other connection categories. In particular:

- they are all in lower density rural areas (using relatively long stretches of our overhead network),
- their load is highly correlated: when it's warm and dry they all switch on,
- their load and combined loading peaks are very flat (and any load management or demand response that aims to reduce these peaks must therefore operate for extended periods of time to be effective), and
- their peak demands occur in summer whereas the overall Orion network peak demands occur in winter.

This category generally applies to all connections with capacity greater than 20 kW where the primary purpose is to pump water to irrigate farmland. Orion determines the connections that are allocated to this category.

Assessed key statistics for irrigation connections (1 April 2019 to 31 March 2020)	Forecast
Number of connections / ICPs	1,066 (average)
Energy volume	136,935 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	0 kW
– contribution to network-wide summer peak (ADMD)	37,331 kW
– contribution to local network peak (AMD)	55,876 kW
– sum of individual connection anytime peaks (Σ AMD)	97,059 kW
Value of lost load (VOLL)	\$1.20 / kWh
Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (i.e. with normal distribution losses added).	

4.4 Major customer connections

We provide a specific category for our larger connections. We determine which connections are in this category based on maximum loading levels (and any contracted capacity for new or modified connections). Generally:

- where the loading or export level is between 150 kVA and 300 kVA the customer (or their retailer) may elect to be classified as a major customer connection, or
- where the loading or export level is above 300 kVA the connection is classified as a major customer connection.

However:

- irrigation connections and streetlighting connections will not be categorised as major customer connections,
- reconciled embedded networks will be classified as major customer connections.

A number of factors affect our cost allocations for these connections, including:

- such connections usually have a dedicated transformer and generally do not use our low voltage network,
- in some cases, we do not own or maintain the transformer, and
- some customers have specific additional requirements in terms of their security of supply and back-up supply options.

In addition to these factors, all connections of this size have half-hour interval metering which gives Orion the opportunity to apply more specific cost-reflective pricing using the metered volumes for each connection.

Assessed key statistics for major customer connections (1 April 2019 to 31 March 2020)	Forecast
Number of connections / ICPs	487 (average)
Energy volume	877,893 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	110,213 kW
– contribution to network-wide summer peak (ADMD)	134,101 kW
– contribution to local network peak (ADMD)	110,213 kW
– sum of individual connection anytime peaks (Σ AMD)	224,366 kW
Value of lost load (VOLL)	\$22.56 / kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (i.e. with normal distribution losses added).

4.5 Large capacity connections

We provide a specific pricing category to accommodate very large connections that require individual pricing consideration as a result of their size and impact on the local network. Such connections may also have:

- enhanced security of supply requirements, including back up supply and restoration obligations
- very specific and dedicated assets, including transmission assets, and associated costs, with significant stranding risk should the connection cease operation
- the ability to enter into long term contracts with us.

As a general guide, and subject to the considerations above, connections requiring a capacity of greater than 10 MVA in the urban area, or greater than 2 MVA in the rural area would be considered for large capacity pricing.

Pricing and charge structures are individually negotiated and charged directly to the customer. Because of this ability to negotiate very connection-specific pricing, we are in an even better position to ensure consistency with the pricing principles. Our contracts with these customers include terms that require us to allocate assets and asset related costs in a manner consistent with the overall pricing methodology including establishing and disclosing:

- assets and asset groups that are used in providing delivery services to the customer including assets provided in order to meet specific security of supply requirements,
- an equitable method for assigning a proportion of the value of assets to the customer for assets that are also used by other customers,
- the current replacement value of the asset allocation above,
- capital costs (return on assets and depreciation) based on the asset allocation above,
- an equitable method for assigning operations, maintenance and administration costs, which may include separate consideration of customer specific costs, asset specific costs, and shared costs,
- an allocation of transmission costs consistent with the overall pricing methodology, and
- a pricing structure that aims to recover allocated costs.

Assessed key statistics for large capacity connections (1 April 2019 to 31 March 2020)	Forecast
Number of connections / ICPs	15 (at 2 locations)
Number of customers	2
Energy volume	155,918 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	9,090 kW
– contribution to network-wide summer peak (ADMD)	27,020 kW
– contribution to local network peak (ADMD)	27,020 kW
– sum of individual connection anytime peaks (Σ AMD)	32,017 kW
Value of lost load (VOLL)	\$59.33 / kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (i.e. with normal distribution losses added).

Large capacity connections have specific non-standard contractual terms including delivery obligations and responsibilities in the event of supply interruptions. These attributes are disclosed in our *Disclosure of prescribed contracts* document which is available on our website.

In general, for these customers we:

- provide uninterrupted supply security against a range of faults by maintaining duplicate supply assets,
- prioritise restoration of supply following outages,
- maintain a “last to shed” priority for grid emergencies, and to the extent reasonably practical, not include the connections for “automatic under frequency load shedding”, nor “automatic under voltage load shedding”.

This supply security is greater than our standard undertakings which are set out in our “security of supply standard” in our published asset management plan.

5 Total costs

Considering a breakdown of our costs allows us to consider the drivers that influence these costs, and establish a pricing basis that reflects different cost drivers.

The table below provides details of the delivery costs that we have forecast for the 2019 - 2020 year, which gives us our total target revenue:

Cost component (1 April 2019 to 31 March 2020)	Forecast \$000	Prior year forecast \$000
Transpower's interconnection charges	52,706	65,836
Transpower's connection and new investment charges	6,505	7,054
Avoided transmission costs	3,262	3,927
Payments to distributed generators in lieu of transmission charges	Nil	132
Recoverable cost (transmission) subtotal	62,473	76,948
IRIS allowance	4,034	Nil
Recoverable cost (incentives) subtotal	4,034	Nil
Local authority rates	3,994	3,810
Electricity Authority levies	600	635
Commerce Commission levies	520	400
Utilities Disputes charges	110	107
Pass through cost (rates and levies) subtotal	5,224	4,952
Payments to distributed generators in lieu of distribution costs	38	62
Administration costs	18,264	15,234
Operations and maintenance costs	47,820	46,761
Payments for interruptible load and power factor correction	1,192	1,114
Depreciation	43,000	40,000
Loss on disposals	2,000	2,000
Asset value (average regulatory asset base, \$000) ¹¹	1,088,500	
Applicable WACC	7.19%	
Return on capital (after	72,653	67,066
Less revenue received from avoided transmission charges	(3,262)	(3,927)
Less sundry revenue	(3,892)	(4,340)
Taxation	20,328	24,200
Cost allocation discount to meet DPP/CPP requirement	(24,902)	(8,288)
Distribution subtotal	173,239	184,834
Delivery total (total target revenue)	244,970	261,783

¹¹ This is our forecast average regulatory asset base (RIV) for the 2019 – 2020 year based on our disclosed RIV prepared in accordance with the Commerce Act (Electricity Distribution Services Input Methodologies) Determination 2012.

¹² \$1,088,500k x 7.19% x (1 - 28% x 25.6%) = \$72,653k.

6 Allocating costs to connection categories

Each of the costs in the section above is individually considered and allocated to connection categories on a basis that reflects our pricing principles - in particular economic efficiency, equitability and practicality – and the key attributes of each category.

We allocate many of our distribution costs based on each category's use of our delivery assets, and to do this it is necessary to first allocate the assets to each category.

6.1 Distribution asset allocation

Our distribution asset allocation method takes account of a number of factors:

- assets are allocated based on our assessment of the relative use of each asset category by each connection category
- the allocation of assets that are largely shared (e.g. sub-transmission assets) is weighted more in favour of each category's contribution to local peak demands (ADMD) on the basis that these assets are sized to meet the combined coincident loadings
- the allocation of assets that are sized to meet the load of individual connections (for example low voltage assets), and those assets that tend to have a fixed size regardless of loading levels (for example land) is weighted more in favour of the sum of each individual connection's anytime peak (Σ AMD)
- the allocation of contingent assets (the assets that are provided to maintain supply after a fault - approximately 17% of our total asset value) is additionally weighted in proportion to each category's value of lost load (VOLL), as this measure reflects the relative need for the assets between the connection categories. We assess VOLL for each connection category as shown in section 4. The range of values we use is reasonably consistent with that from other sources¹³ and ranges between \$1 and \$59 per kilowatt hour (much higher than the normal retail cost of delivered electricity which ranges from 12¢ to 30¢ per kilowatt hour).

We initially allocate assets based on the replacement cost and detailed asset assessment contained in our latest audited regulatory valuation prepared in accordance with the Commission's optimised deprival value (ODV) methodology, prepared as at 31 March 2004.

¹³ For example the Authority in its 2013 paper "Investigation into the Value of Lost Load in New Zealand" estimated a range of \$11 per kWh to \$70 per kWh for a number of customer types in the Christchurch area. See: <http://www.ea.govt.nz/dmsdocument/15385>.

The resulting allocations by asset category are:

Allocation of distribution assets (based on 31 March 2004 ODV replacement costs)

Asset category	Street lighting	General	Irrigation	Major customer	Large capacity*	Total
	\$000	\$000	\$000	\$000	\$000	\$000
Subtransmission	1,211	191,189	23,423	50,467	8,700	274,990
Power Transformers	196	31,057	2,474	8,423	2,949	45,099
11kV Distribution	1,176	196,436	28,271	56,555	1,244	283,682
Land & Property	226	69,858	3,218	8,214	2,189	83,706
Distribution Transformers	320	84,072	4,956	8,744	81	98,173
Low voltage distribution	91	237,042	1,394	7,394	0	245,922
Lighting	14,577	0	0	0	0	14,577
Total	17,797	809,654	63,735	139,798	15,163	1,046,147

* New assets constructed for this category after the date of our ODV valuation are added in at their ODV-equivalent cost.

Notable entries in this table include:

- Major customers are allocated only a very small share (3%) of the low voltage distribution network assets when compared with their share of subtransmission (18%) and 11kV distribution assets (20%). This reflects their very limited use of LV assets.
- Large capacity connections are allocated no LV asset costs.
- all of the lighting network asset costs are allocated to the streetlighting connection category.

We then allocate our forecast average regulatory asset value (average RIV) to each category in proportion to the allocation of replacement costs. We use this method to allocate RIV because it:

- captures the change in asset value between our valuation date and the pricing year
- ensures that the same proportion of depreciation is applied to the assets assigned to all connection categories, reflecting that we provide an ongoing service, rather than a service with diminishing value (in other words a delivery service provided with older assets is no less valuable than a service provided with new assets)
- captures and assigns assets that are used for our delivery service, but are not included in our ODV (such as working capital, our faults vehicles and head office building).

The average RIV represents the indexed regulatory depreciated investment value of assets averaged over the year. The resulting allocation of average RIV for each connection category is:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	\$000	\$000	\$000	\$000	\$000	\$000
Average RIV allocation	18,547	843,766	66,420	145,688	14,079	1,088,500

The full detail of the asset allocation calculations is not shown in this methodology as it is a complicated process involving many interacting components. However, by way of one example a diagram showing how the low voltage distribution assets are allocated to the general connection category is in Appendix D.

6.2 Recoverable cost (transmission) cost allocation

The investment in and capacity of the transmission system bringing electricity to our region is largely driven by the peak loadings within the greater upper South Island area. This is reflected in Transpower's interconnection charge (the main component of their charges to us) which is based on our contribution to Transpower's regional (in this case upper South Island) coincident peak demand (RCPD). This generally occurs in winter and is measured over the top 100 half hourly demands.

However, our distribution network load is characterised by summer (rural) and winter (urban) seasonal peaks and, to the extent that all connection categories use the transmission service, and benefit from it, we have split the costs equally between the categories in proportion to their transmission demands (using network wide ADMD). We then allocate the additional cost of meeting the higher winter peak only to connection categories that contribute to the winter peak.

This approach provides a smooth transition in the cost allocation as the observed summer peaks increase and approach the winter peaks.

We allocate a proportion of Transpower's other charges (for connection assets and new investment agreements) to the large capacity category based on actual use of assets, and allocate the remainder of these charges to all other connection categories in proportion to each category's contribution to anytime maximum demand (Σ AMD).

Finally, we allocate the cost of any transmission alternatives that we procure and according to Σ AMD as it is an alternative to connection assets.

In summary:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	\$000	\$000	\$000	\$000	\$000	\$000
Transpower's interconnection charges	171	37,306	1,663	11,876	1,690	52,706
Transpower's connection and new investment charges	15	4,773	235	544	937	6,505
Avoided transmission investment	9	2,796	138	319	0	3,262
Transmission cost allocation	196	44,875	2,036	12,739	2,628	62,473

6.3 Recoverable cost (incentives) cost allocation

This incentive allowance currently relates to savings on operating and maintenance expenditure, and as such, we have allocated it to each connection category in proportion to our allocation of assets (consistent with our allocation of operating and maintenance below).

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
IRIS allowance	69	3,134	247	541	44	4,034

6.4 Pass through cost allocation

The main component (nearly 80%) of pass through costs is local authority rates, and these reflect the value of our assets. For simplicity we have allocated all pass through costs in proportion to our allocation of assets. The resulting cost allocations are:

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Local authority rates	68	3,102	244	536	44	3,994
Electricity Authority levies	10	466	37	80	7	600
Commerce Commission levies	9	404	32	70	6	520
Utilities Disputes charges	2	85	7	15	1	110
Rates and levies	89	4,057	319	701	58	5,224

6.5 Distributed generation distribution cost allocation

The distribution components of our export credits reflect the savings in distribution costs gained from this generation contribution. The cost reduction provided by distributed generators relates to their ability to lower our peak loading, and we allocate the cost of providing these credits based on each connection category's contribution to peak loadings (ADMD), with the following result:

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Distribution component of export credits	0	28	3	6	0	38

6.6 Payments for interruptible load and power factor correction

Our irrigation rebate scheme allows us to avoid investment in capacity upgrades and back up supply assets. These schemes lower our overall cost of service and are funded by all categories and we allocate the costs in proportion to our allocation of assets:

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Payments for rebates	21	936	74	162	0	1,192

6.7 Administration cost allocation

Costs associated with administration and overheads are largely independent of asset value, so we instead allocate these costs to each connection category in proportion to the sum of individual connection anytime peaks (Σ AMD), as this reflects the extent to which each connection utilises our service. The resulting allocation is:

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Administration cost allocation	50	15,483	764	1,766	201	18,264

6.8 Operations and maintenance cost allocation

Operations and maintenance costs are asset related and we allocate these to each connection category in proportion to our allocation of assets.

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Operations and maintenance cost allocation	816	37,141	2,924	6,413	526	47,820

6.9 Cost of capital allocation (depreciation, return on capital and taxation)

Capital costs are all asset related, and we allocate these costs to connection categories in proportion to our allocation of assets. Offsetting these costs, we also provide a credit reflecting costs covered by avoided transmission charges. The resulting cost allocations are:

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Depreciation cost allocation	736	33,494	2,637	5,783	350	43,000
Loss on disposals	35	1,571	124	271	0	2,000
Applicable WACC (7.19%)	1,238	56,302	4,432	9,721	961	72,653
Taxation cost allocation	348	15,838	1,247	2,735	161	20,328
Costs funded by avoided transmission	(9)	(2,796)	(138)	(319)	0	(3,262)
Costs funded by sundry revenue	(11)	(3,336)	(165)	(380)	0	(3,892)
Total cost of capital allocation	2,337	101,071	8,136	17,811	1,472	130,827

6.10 Target revenue adjustments and total cost allocation

The final step in establishing the total cost allocation for each connection category is to adjust (currently by way of a discount) the allocation to meet the requirements of the default price-quality path.

When applying this discount, we consider the impact of any changes in our cost allocation from previous years. From year to year, each category's contribution to our costs varies, as loadings and other factors change, and to provide some price stability we vary the discount to spread any significant changes in cost allocations over two to three years.

While the adjustments for transmission costs are shown separately, it is the combined transmission and distribution adjustments that represent the discount to our return on capital applied to each category.

Adding together each of the individual cost allocations (sections 6.2 to 6.9 above) gives our total target revenue for each connection category.

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
Transmission costs allocation	196	44,875	2,036	12,739	2,628	62,473
Cost discount	0	23	(30)	7	0	0
Target recoverable cost (transmission) revenue	196	44,898	2,006	12,746	2,628	62,473
Target recoverable cost (incentives) revenue	69	3,134	247	541	44	4,034
Target pass through cost (rates and levies) revenue	89	4,057	319	701	58	5,224
Distributed generation cost allocation	0	28	3	6	0	38
Payments for rebates	21	936	74	162	0	1,192
Administration cost allocation	50	15,483	764	1,766	201	18,264
Operations and maintenance cost allocation	816	37,141	2,924	6,413	526	47,820
Total cost of capital allocation	2,337	101,071	8,136	17,811	1,472	130,827
Cost discount	(421)	(19,175)	(1,995)	(3,311)	0	(24,902)
Target distribution revenue	2,803	135,484	9,906	22,847	2,199	173,239
Total target revenue	3,156	187,574	12,478	36,834	4,928	244,970
Resulting return on capital	4.7%	4.7%	3.9%	4.7%	7.3%	4.7%

6.11 Comparison with prior target revenue

The following table shows a comparison with the target revenues from the prior pricing methodology. Changes often reflect a change in size or utilisation by a connection category, and are therefore not proportional to changes in price which are set out in the following section.

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	\$000	\$000	\$000	\$000	\$000	\$000
Total target revenue (from above)	3,156	187,574	12,478	36,834	4,928	244,970
Prior year total target revenue	3,217	204,729	12,188	37,745	3,904	261,783
Increase (reduction)	(61)	(17,155)	290	(911)	1,024	(16,813)
Percentage increase (reduction)	(1.9%)	(8.4%)	2.4%	(2.4%)	26.2%	(6.4%)

7 Pricing structure and prices

We aim to structure our prices to provide cost reflective pricing signals to the users of our service. This promotes economic efficiencies in that customers can adjust their behaviour to reduce their delivery costs, and this change in behaviour provides a corresponding saving for us by avoiding or deferring investment.

The following sections:

- explain our determination of pricing structures for each connection category,
- provide our rationale for and forecast of chargeable quantities for each price component, and
- derive distribution and transmission parts of our delivery prices that provide the total target revenues established in section 6 above.

The final derived delivery prices are summarised in the schedules in Appendix A, *Delivery prices* and *Export credits*.

Customer funded assets

We receive capital contributions toward the construction of new assets and network extensions. These contributions are not treated as revenue from a regulatory perspective and, consistent with this, any assets vested in us enter our RIV at the amount we pay, not at the cost of building them, while cash contributions are deducted from our capital expenditure in determining net additions to our RIV. This approach ensures that we do not make a return on assets that have been provided by others.¹⁴

¹⁴ See our Connections and Extensions Policy for a description of how we assess contributions. This document also states the contribution amounts for small and medium sized-connections. The document is available on our website: www.oriongroup.co.nz/ConnectionsAndExtensionsPolicy

7.1 Reflecting our long run average incremental costs (LRAIC)

A key aspect in establishing our pricing structure is to ensure that our prices are cost reflective. This supports appropriate decisions both by customers in using our network, and by Orion in investing in our network.

The most significant cost driver that influences our delivery service is the combined (coincident) peak demand of all customers (ADMD). We design and construct much of our network to meet this combined peak load. We consider that approximately 50% of our distribution costs are directly dependent on the coincident peak loading (the remainder of our costs are either fixed or dependent on the peak demand of individual customers or groups of customers).

To reflect this peak demand (ADMD) cost driver in our pricing, we have derived the long run average incremental cost (LRAIC) of delivery during peak loading periods and have reflected this in our pricing structure, as noted in the following sections. The LRAIC is the replacement cost of the proportion of our distribution assets that is load dependent, divided by the peak demand. Apart from minor differences due to the unit and point of measurement, the LRAIC is calculated on an equivalent basis for all relevant connection categories. See Appendix E for a summary of our calculation of the LRAIC.

The LRAIC is updated every year.

The LRAIC is not intended to support pricing as a means of managing localised or short term capacity issues. Rather, it is an estimate of the how much it typically costs us to provide a distribution network solution to support demand. This can then be set against alternatives, and in particular demand response.

7.2 Streetlighting connections

Energy used by streetlighting connections is subject to our general connection prices applied to GXP reconciled volumes (including peak demands). While these prices are set in relation to the characteristics of the general connection category, we consider that they do provide adequate reflection of costs and incentives to maximise the efficiency of lights. However, the revenue collected does not cover the total cost allocation, mainly due to the additional cost to provide our dedicated lighting circuits for this category.

Lighting circuits are generally a standard size and are not constrained. We consider that a fixed daily charge per connection reasonably reflects the fixed costs associated with these circuits, which is used to recover the balance of the revenue requirement.

The standard general pricing for transmission charges collects a little more than the transmission cost allocation, and this over-recovery is offset with a reduction to the fixed daily charge.

Finally, pass through and incentive recovery allocations are also collected with small additions to the fixed daily charge.

Charge	Chargeable quantity	Price component	Price	Revenue (\$000)
Fixed daily charge	49,513 connections	Recoverable cost (transmission)	(\$0.0038)/conn/day	(69)
		Recoverable cost (Incentives)	\$0.0038/conn/day	69
		Pass through cost (rates and levies)	\$0.0049/conn/day	89
		Distribution	\$0.1084/conn/day	1,964
		Delivery	\$0.1133/conn/day	2,053
Peak charge	2,683 kW	Recoverable cost (transmission)	\$0.1450/kW/day	142
		Distribution	\$0.2842/kW/day	279
		Delivery	\$0.4292/kW/day	421
Volume charges				
Weekdays (Mon to Fri, 7am to 9pm)	3,464 MWh	Recoverable cost (transmission)	\$0.01517/kWh	53
		Distribution	\$0.06042/kWh	209
		Delivery	\$0.07559/kWh	262
Nights & weekends (Sat & Sun)	23,259 MWh	Recoverable cost (transmission)	\$0.00297/kWh	69
		Distribution	\$0.01501/kWh	349
		Delivery	\$0.01798/kWh	418
Overall total				3,155

The table below compares projected revenue against target revenue for each price component.

Price component	Target (\$000)	Actual (\$000)
Recoverable cost (transmission)	196	195
Recoverable cost (Incentives)	69	69
Pass through cost (rates and levies)	89	89
Distribution	2,803	2,802
Delivery	3,156	3,155

7.3 General connections

Our general connection category covers the vast majority of our connections ranging from small to large residential, and small to medium commercial connections.

As noted above we consider that a key cost driver in providing our delivery service is the coincident peak demand of all connections, and the cost of building our network to meet this, which is the LRAIC defined above. Our calculations support an LRAIC of \$104 per kW per year for general connections. The peak period demand price is set to align with the updated calculation at a price level of \$104 per kW per year (expressed as a daily price of \$0.2842 per kW per day).

In addition, the winter based allocation of transmission interconnection charges is also recovered via the peak period demand price with a price of \$53 per kW per year (expressed as a daily price of \$0.1450 per kW per day).

The application of this peak price for general connections is described in our separate *Pricing policy* document. In short, chargeable peak demands are measured over the winter period May to August during the 100 or so hours when total network demand is highest. We signal these periods (using ripple signals, text and email) to support customer response.

Costs associated with the rest of the revenue requirement is not related to usage or peak loading levels, and we aim to collect this revenue in an equitable way and minimise incentives that might distort behaviour.

The first part is met with the application of a 15 cents per connection per day fixed charge, which is the maximum universal amount that can be applied under the Low User Fixed Charge regulations. A fixed daily charge is effective as it does not provide inefficient usage incentives.

The balance of our revenue requirement, including the balance of allocated transmission costs, are currently met with the application of traditional volume based pricing. Recognising the different load profiles of customer groups within this connection category and to ensure all customers contribute, we recover 80% through the application of weekday-based volume pricing, and 20% through the less-utilised night and weekend based volume pricing, which has lower utilisation (particularly among some subgroups of consumers).

Low power factor charge

A low power factor charge may apply in situations where a general connection has a power factor materially below 0.95 lagging. This charge allows Orion to encourage customers to improve their power factor so that we avoid having to carry out additional network reinforcement. We do not expect the charge to apply in many cases or to be a significant revenue item.

Charge	Chargeable quantity	Price component	Price	Revenue (\$000)
Fixed daily charge	201,095 connections	Recoverable cost (Incentives)	\$0.0426/conn/day	3,135
		Pass through cost (rates and levies)	\$0.0551/conn/day	4,055
		Distribution	\$0.0523/conn/day	3,849
		Delivery	\$0.1500/conn/day	11,040
Peak charge	475,023 kW	Recoverable cost (transmission)	\$0.1450/kW/day	25,209
		Distribution	\$0.2842/kW/day	49,411
		Delivery	\$0.4292/kW/day	74,620
Volume charges				
Weekdays (Mon to Fri, 7am to 9pm)	1,066,255 MWh	Recoverable cost (transmission)	\$0.01517/kWh	16,175
		Distribution	\$0.06042/kWh	64,423
		Delivery	\$0.07559/kWh	80,598
Nights & weekends (Sat & Sun)	1,185,813 MWh	Recoverable cost (transmission)	\$0.00297/kWh	3,522
		Distribution	\$0.01501/kWh	17,799
		Delivery	\$0.01798/kWh	21,321
Low power factor	0 kVAr	Recoverable cost (transmission)	\$0.0500/kVAr/day	0
		Distribution	\$0.1500/kVAr/day	0
		Delivery	\$0.2000/kVAr/day	0
Overall total				187,579

The table below compares projected revenue against target revenue for each price component.

Price component	Target (\$000)	Actual (\$000)
Recoverable cost (transmission)	44,898	44,906
Recoverable cost (Incentives)	3,134	3,135
Pass through cost (rates and levies)	4,057	4,055
Distribution	135,484	135,482
Delivery	187,574	187,579

7.4 Irrigation connections

As noted in section 4 above, this category reflects irrigators' unique loadings and associated costs.

Energy used by irrigation connections is subject to our general connection volume prices applied to GXP reconciled volumes, and this provides a significant proportion of the revenue requirement for the category. Irrigators do not contribute to the GXP based peak charge set for general connections because they are not running during our peak periods that occur on the coldest winter days. Instead, we set a much lower demand charge based on the capacity rating of each irrigation pump motor to meet the balance of our revenue requirement for the category.

This price structure recognises that our delivery costs are primarily driven by the relatively constant load of pump motors (measured via their capacity rating), which show very little diversity during the irrigation season, rather than their diversified combined loading. (In other words, we generally reach a point where all irrigators are on at the same time, and this behaviour sets the network peaks in the rural parts of our network.) It also allows us to recognise this category's relatively small contribution to our winter-based transmission costs.

Power factor correction rebate (optional)

Most irrigation connections are eligible to apply for our power factor correction rebate. This rebate is provided to encourage more efficient use of our rural overhead network where improved power factor can avoid the need for network reinforcement.

We consider that it is most economical to correct poor power factors at the source of the problem, in this case the irrigation pump motor, and we set this rebate to ensure that customers receive a reasonable payback on their investment in power factor correction equipment.

Interruptibility rebate (optional)

Many irrigation connections are eligible to apply for our interruptibility rebate. Using our interruptibility rebate arrangement, we contract with irrigators to be first to be cut off in a capacity emergency, and this allows us to provide a higher level of service to other customers with more critical loads.

The rebate arrangement provides a lower cost alternative method for us to meet our security of supply standards, and we set the price at a level that is sufficient to attract the required level of load reduction.

Charge	Chargeable quantity	Price component	Price	Revenue (\$000)
Capacity charge	78,170 kW	Recoverable cost (transmission)	\$0.0630/kW/day	901
		Recoverable cost (Incentives)	\$0.0172/kW/day	246
		Pass through cost (rates and levies)	\$0.0223/kW/day	319
		Distribution	\$0.3671/kW/day	5,251
		Delivery	\$0.4696/kW/day	6,718
Volume charges				
Weekdays (Mon to Fri, 7am to 9pm)	57,247 MWh	Recoverable cost (transmission)	\$0.01517/kWh	868
		Distribution	\$0.06042/kWh	3,459
		Delivery	\$0.07559/kWh	4,327
Nights & weekends (Sat & Sun)	79,688 MWh	Recoverable cost (transmission)	\$0.00297/kWh	237
		Distribution	\$0.01501/kWh	1,196
		Delivery	\$0.01798/kWh	1,433
Rebates*				
Power factor correction	24,397 kVAr	Distribution	(\$0.1755)/kVAr/day	
		Delivery	(\$0.1755)/kVAr/day	
Interruptibility rebate	50,853 kW	Distribution	(\$0.0439)/kW/day	
		Delivery	(\$0.0439)/kW/day	
*Rebates are not included in the total revenue because they are funded across all connection categories (see section 6.6).				
Overall total				12,478

The table below compares projected revenue against target revenue for each price component.

Price component	Target (\$000)	Actual (\$000)
Recoverable cost (transmission)	2,006	2,006
Recoverable cost (Incentives)	247	246
Pass through cost (rates and levies)	319	319
Distribution	9,906	9,906
Delivery	12,478	12,478

7.5 Major customer connections

A key cost driver in providing our delivery service is the coincident peak demand of all connections. The cost of reinforcing our network to meet this peak demand is reflected in our assessment of the long run average incremental cost – the LRAIC, as defined above. For major customer connections our updated assessment of the LRAIC (based on demands metered at the connection rather than the GXP) is \$96 per kVA per year. The control period demand price is set to align with the updated calculation at a price level of \$96 per kVA per year (expressed as a daily price of \$0.2641 per kVA per day).

The winter based allocation of transmission interconnection charges is also recovered via the control period demand price with a price of \$55 per kVA per year (expressed as a daily price of \$0.1507 per kVA per day).

The application of this peak price for major customer connections is described in our separate *Pricing policy* document. In short, chargeable peak demands are measured over the winter period May to August during the 80 or so hours when total network demand is highest. We signal these periods (using ripple signals, text and email) to support customer response.

We also provide some dedicated equipment for major customer connections and the prices are included in the price schedule in Appendix A. We set our prices to cover all costs and reflect the competitive nature of this aspect of our service.

The fixed costs associated with managing this pricing category and processing half-hour interval metering information, as well as a contribution toward the non-load related operational costs of the network is reflected in our fixed charges. Finally, we recover the balance of our distribution revenue requirement and the balance of the transmission cost allocation through the prices that are applied to customers' maximum demands.¹⁵

¹⁵ See our separate *Pricing policy* document for the details on how demands are measured.

Charge	Chargeable quantity	Price component	Price	Revenue (\$000)
Fixed charges				-
Daily connection charge	487 connections	Distribution	\$10.0000/conn/day	1,782
		Delivery	\$10.0000/conn/day	1,782
Extra switches	109 switches	Distribution	\$3.6700/switch/day	146
		Delivery	\$3.6700/switch/day	146
11kV metering equipment	47 connections	Distribution	\$4.4500/conn/day	77
		Delivery	\$4.4500/conn/day	77
11kV underground cabling	5.70 km	Distribution	\$3.2900/km/day	7
		Delivery	\$3.2900/km/day	7
11kV overhead lines	3.20 km	Distribution	\$2.0700/km/day	2
		Delivery	\$2.0700/km/day	2
Transformer capacity	326,065 kVA	Distribution	\$0.0138/kVA/day	1,647
		Delivery	\$0.0138/kVA/day	1,647
Control period demand charge	107,361 kVA	Recoverable cost (transmission)	\$0.1507/kVA/day	5,922
		Distribution	\$0.2641/kVA/day	10,379
		Delivery	\$0.4148/kVA/day	16,301
Capacity charges				
Nominated maximum demand	262,590 kVA	Recoverable cost (transmission)	\$0.0090/kVA/day	865
		Recoverable cost (Incentives)	\$0.0056/kVA/day	538
		Pass through cost (rates and levies)	\$0.0073/kVA/day	702
		Distribution	\$0.0916/kVA/day	8,803
		Delivery	\$0.1135/kVA/day	10,908
Metered maximum demand	228,370 kVA	Recoverable cost (transmission)	\$0.0713/kVA/day	5,959
		Delivery	\$0.0713/kVA/day	5,959
Overall total				36,830

The table below compares projected revenue against target revenue for each price component.

Price component	Target (\$000)	Actual (\$000)
Recoverable cost (transmission)	12,746	12,746
Recoverable cost (Incentives)	541	538
Pass through cost (rates and levies)	701	702
Distribution	22,847	22,844
Delivery	36,834	36,830

7.6 Large capacity connections

Orion provides a specific pricing category to accommodate very large connections that require individual pricing consideration as a result of their size and impact on the local network. We give specific consideration to the assets involved and the loading contributions which determine the network capacity required and any additional charges from Transpower.

Pricing and charge structures are negotiated directly with the customers. The table below compares projected revenue against target revenue for each pricing component.

Price component	Target (\$000)	Actual (\$000)
Recoverable cost (transmission)	12,745	12,746
Recoverable cost (Incentives)	541	538
Pass through cost (rates and levies)	701	702
Distribution	22,892	22,893
Delivery	36,879	36,879

7.7 Revenue summary

The table below summarises the total projected revenue from the transmission and distribution parts of our pricing for each of the connection categories for 2019 - 20, and shows how this (and associated prices) have changed compared to the projection for the previous (2018-19) year. Changes in revenue are a product of both changes in price and changes in chargeable quantities, and these are also set out in the table:

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
<i>Projected revenue 2019-20</i>						
Distribution	2,960	142,673	10,471	24,084	2,300	182,488
Transmission	195	44,906	2,006	12,746	2,628	62,482
Delivery	3,155	187,579	12,478	36,830	4,928	244,970
<i>Revenue change compared to previous year</i>						
Distribution	(28)	(4,496)	459	1,020	710	(2,336)
Transmission	(36)	(12,650)	(169)	(1,931)	314	(14,472)
Delivery	(64)	(17,146)	290	(911)	1,024	(16,808)
<i>Weighted average price change compared to previous year</i>						
Distribution	(3.2%)	(2.5%)	1.3%	(1.2%)	2.8%	(2.1%)
Transmission	(20.4%)	(21.8%)	(9.7%)	(16.6%)	(13.9%)	(20.2%)
Delivery	(4.4%)	(7.9%)	(0.6%)	(7.2%)	(7.5%)	(7.4%)
<i>Weighted average quantity change compared to previous year</i>						
Distribution	2.4%	(0.7%)	2.8%	5.3%	41.9%	0.6%
Transmission	6.3%	(0.2%)	1.6%	4.1%	34.6%	1.7%
Delivery	2.6%	(0.6%)	2.6%	4.8%	37.4%	0.9%

The changes in revenues and prices reflect our estimates of the changes in total costs, the allocation of those to each connection category according to our cost allocation methodology, our projections of movements in chargeable quantities, our contractual commitments (in some cases) and the price regulation that we face.

Overall distribution price movements reflect the DPP determination applicable to Orion at this time. Revenue is then the DPP compliant distribution prices multiplied by the projected quantities.

Overall transmission price movements reflect changes in transmission costs and in the projected quantities over which they are recovered (that is, higher chargeable quantities allow us to set a lower price, and vice versa).

Compared to previous prices, the main factors contributing to the overall distribution price movement highlighted above are:

Regulated CPI allowance of 1.53%	+\$2.5m	+1.4%
Regulated rate of change allowance of 0%	\$0.0m	+0.0%
Removal of regulated earthquake catch up allowance	-\$9.5m	-5.3%
Regulated operating expenditure incentive allowance	+\$4.0m	2.2%
Increase in pass through costs (rates and levies)	+\$0.3m	0.2%
Removal of customised price path administrative cost recovery	-\$0.4m	-0.2%
Pricing closer to the regulated limit	+\$0.2m	+0.1%
Reduction in regulated avoided transmission allowances	-\$0.8m	-0.4%
Other minor variations		0.0%
Combined		-2.1%

Individual unit prices are set out against previous prices in a schedule in Appendix A, showing changes and percentage changes to each.

8 Credits for export

Distributed generation that reliably generates during peak demand times can provide an economical alternative to electricity delivery and we provide export credits in recognition of this benefit to the network.

The credits do not represent the purchase of electricity, and exporting customers are able to separately negotiate to sell exported energy, usually to their electricity retailer.

Payments to generators are a cost incurred in providing our delivery service and, as with all other delivery costs, must be recovered from the customers that use our delivery service. The cost allocations in section 6.5 above show the assignment of these costs to connection categories.

We do not specifically charge customers for exporting electricity to our network, however, customers would be expected to fund any costs associated with situations where our network needed to be upgraded to accommodate the exported electricity. Separately, the nominated maximum demand charge for major customers, which broadly reflects the sizing of network delivery assets near the customer, is based on the higher of load or export demands, so any peak export that exceeds peak load will increase delivery charges.

Standard export credit prices

Export credits are based on the amount of electricity injected into our network during peak loading periods. The cost of delivery during peak loading is represented by our assessment of LRAIC which we calculate as \$105 per kW per year (as noted in section 7.3 above).

Some of the costs represented in this LRAIC are not alleviated via export – for example, the required size for distribution transformers and low voltage systems is usually unchanged when generation is installed. Consequently, we set the distribution credit price below the full LRAIC to reflect this.

We then separate the credit between real (kW) and reactive (kVAr) components of export, and we cap the amount of reactive export that is eligible for credits, to encourage appropriate levels of each.

Different categories are maintained to generally reflect the different metering information available from different sites, and standard credits are capped at 750 kW of generation – above this level we individually consider the benefits to the network and apply specific pricing. We set a lower credit price for export that includes PV and where the metering arrangement only records total monthly export (referred to as “non-half-hour metering”), rather than the actual time that energy was exported. The lower price reflects average coincidence between export from PV generation and our network peak demands (usually occurring on cold winter days and evenings) that we observe at connections that do have the necessary metering for this assessment.

Exporting generators also reduce our exposure to Transpower’s interconnection charges if they generate during Transpower’s regional coincident peak demand periods. The Electricity Authority has revised the rules so that we are only able to reflect this savings in the credits applied to customers for generating connections that they approve, and at the date of this publication, no connections have been approved.

Generation credit prices

We previously operated a generation credit arrangement to reduce loading levels via generation support at other times. As a result of reliability and administrative issues, we closed the scheme to new generation in 2017. With the approval restrictions for transmission savings noted above, we withdrew the credits effective 1 April 2019.

Appendix A - Price schedules

Electricity delivery price schedule for Orion NZ Ltd

(applicable from 1 April 2019)



This schedule lists the wholesale prices that Orion uses to charge electricity retailers and directly contracted customers for the electricity delivery service in Orion's network area. This delivery service includes the transmission and distribution of electricity to homes and businesses, but does not include the cost of the electricity itself. Please refer to your electricity retailer for details of retail electricity prices. The components of the total delivery price are shown in order to meet information disclosure and price path compliance requirements.

	Price breakdown				Delivery	
All prices exclude GST	Transmission	Incentives and Recoveries	Rates and Levies	Net Distribution	Price (total)	Unit of measure
Streetlighting connections		approx 49,513 connections				
Fixed charge	(0.0038)	0.0038	0.0049	0.1084	0.1133	\$/con/day
Peak charge (peak period demand)	0.1450			0.2842	0.4292	\$/kW/day
Volume charge						
Weekdays (Mon to Fri, 7am to 9pm)	0.01517			0.06042	0.07559	\$/kWh
Nights & weekends (Sat & Sun)	0.00297			0.01501	0.01798	\$/kWh
General connections		approx 201,095 connections				
Fixed charge		0.0426	0.0551	0.0523	0.1500	\$/con/day
Peak charge (peak period demand)	0.1450			0.2842	0.4292	\$/kW/day
Volume charge						
Weekdays (Mon to Fri, 7am to 9pm)	0.01517			0.06042	0.07559	\$/kWh
Nights & weekends (Sat & Sun)	0.00297			0.01501	0.01798	\$/kWh
Low power factor charge	0.0500			0.1500	0.2000	\$/kVAr/day
Irrigation connections		approx 1,066 connections				
Capacity charge	0.0630	0.0172	0.0223	0.3671	0.4696	\$/kW/day*
Volume charge						
Weekdays (Mon to Fri, 7am to 9pm)	0.01517			0.06042	0.07559	\$/kWh
Nights & weekends (Sat & Sun)	0.00297			0.01501	0.01798	\$/kWh
Rebates						
Power factor correction rebate				(0.1755)	(0.1755)	\$/kVAr/day*
Interruptibility rebate				(0.0439)	(0.0439)	\$/kW/day*
*applied from 1 October to 31 March only						
Major customer and embedded network connections		approx 487 connections				
Fixed charge				10.0000	10.0000	\$/con/day
Extra switches				3.6700	3.6700	\$/switch/day
11kV Metering equipment				4.4500	4.4500	\$/con/day
11kV Underground cabling				3.2900	3.2900	\$/km/day
11kV Overhead lines				2.0700	2.0700	\$/km/day
Transformer capacity				0.0138	0.0138	\$/kVA/day
Peak charge (control period demand)	0.1507			0.2641	0.4148	\$/kVA/day
Nominated maximum demand	0.0090	0.0056	0.0073	0.0916	0.1135	\$/kVA/day
Metered maximum demand	0.0713				0.0713	\$/kVA/day
Large capacity connections		15 connections				
Individually assessed prices advised and charged directly to the customers						
Miscellaneous						
Monthly invoice and contract charge to retailers and directly contracted customers				30.00	30.00	\$/invoice
Failure to pay notice				50.00	50.00	\$/notice
Default and termination notice				100.00	100.00	\$/notice

Notes

- Full details on how we apply these prices are included in our *Pricing Policy* document, available on our website.
- Peak and volume prices for streetlighting, general connections and irrigation connections are applied to peak loadings and volumes derived from measurements taken at grid exit points, and it is appropriate to allow for normal network losses when assessing the contribution individual connections make to these charges. All other prices in this schedule are applied against measurements or ratings taken at the

Export credit schedule for Orion NZ Ltd

(applicable from 1 April 2019)



This schedule lists the credit prices that we use to credit electricity retailers or directly contracted customers for exports or contributions from their distributed generation. The credits do not represent the purchase of electricity. They are a recognition of the value to Orion in providing its delivery service. Credits are only available for generation approved by Orion and customers must apply in advance.

For exporting generators that were in place prior to 6 December 2016 and approved by the Electricity Authority an additional credit reflecting any actual savings in Transpower charges is available (at the date of issue of this schedule, no exporting generators have been approved by the Electricity Authority). In addition to applying for our distribution credit, exporting customers can approach Transpower (for example, under Transpower's demand response program) for recognition of any transmission benefit, and approach their electricity retailer for recognition of the value of energy exported.

Export credits are based on electricity exported only during specific time periods. Our prices for credits are:

(excluding GST)				
Generator rated output	Period applied	Credit prices	Price Component Code ³	Unit of measure
0 - 30kW generation ²				
Anytime credits (without PV), or	Anytime	0.00370	EXPA	\$/kWh
Anytime credits (with PV)	(24 hours, 7 days)	0.00010	EXPAPV	\$/kWh
0 - 30kW generation ²				
Peak period credits (with or without PV)	Chargeable peak period	0.26260	EXPP	\$/kWh
30 - 750kW Control period credits ⁴				
- real power, plus	Chargeable control	0.0897	EXPCP1	\$/kW/day
- reactive power ⁵	period	0.0295	EXPCP2	\$/kVAr/day
above 750kW	Individually assessed prices provided on application			

Notes for export credit pricing

1. Full details, including metering requirements and how credit prices are applied, are available in our *Export Credits Policy* document available on our website.
2. Small 0 to 30kW generators may elect (in advance) to receive the alternative peak period based credits, subject to the installation of appropriate metering to record peak period export.
3. The price component code is used in our mandatory 'electricity information exchange protocol' files.
4. Control period credits are assessed during control periods and applied as an annual credit at 365/366 times the daily credit price.
5. The credit quantity for reactive power (kVAr) export is limited to 33% of the credit quantity for real power (kW) export in each half hour period, the equivalent of exporting with a 0.95 lagging power factor.
6. Approximately 11 connections are approved for export credits.

Schedule of changes to electricity delivery prices

(effective from 1 April 2019)



This schedule lists changes to the wholesale prices that Orion uses to charge electricity retailers and directly contracted customers for the electricity delivery service in Orion's network area. This delivery service includes the transmission and distribution of electricity to homes and businesses, but does not include the cost of the electricity itself.

Connection categories and price components	Units	Previous delivery price (1 April 2018 to 31 March 2019)	New delivery price (from 1 April 2019)	Change	Percentage change
Streetlighting connections					
Fixed charge	\$/con/day	0.1211	0.1133	-0.008	-6.4%
Peak charge (peak period demand)	\$/kW/day	0.5181	0.4292	-0.089	-17.2%
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)	\$/kWh	0.09316	0.07559	-0.01757	-18.9%
Nights & weekends (Sat & Sun)	\$/kWh	0.01193	0.01798	+0.00605	+50.7%
General connections					
Fixed charge	\$/con/day	-	0.1500	+0.1500	NA
Peak charge (peak period demand)	\$/kW/day	0.5181	0.4292	-0.0889	-17.2%
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)	\$/kWh	0.09316	0.07559	-0.01757	-18.9%
Nights & weekends (Sat & Sun)	\$/kWh	0.01193	0.01798	+0.00605	+50.7%
Low power factor charge	\$/kVAr/day	0.2000	0.2000	-	-
Irrigation connections					
Capacity charge*	\$/kW/day	0.4350	0.4696	+0.0346	+8.0%
Volume charges					
Weekdays (Mon to Fri, 7am to 9pm)	\$/kWh	0.09316	0.07559	-0.01757	-18.9%
Nights & weekends (Sat & Sun)	\$/kWh	0.01193	0.01798	+0.00605	+50.7%
Rebates					
Power factor correction rebate*	\$/kVAr/day	(0.1793)	(0.1755)	-0.0038	-2.1%
Interruptibility rebate*	\$/kW/day	(0.0448)	(0.0439)	-0.0009	-2.0%
* applied from 1 October to 31 March only					
Major customer and embedded network connections					
Fixed charge	\$/con/day	7.5000	10.0000	+2.5000	+33.3%
Extra switches	\$/switch/day	3.6100	3.6700	+0.0600	+1.7%
11kV Metering equipment	\$/con/day	4.3700	4.4500	+0.0800	+1.8%
11kV Underground cabling	\$/km/day	3.2300	3.2900	+0.0600	+1.9%
11kV Overhead lines	\$/km/day	2.0300	2.0700	+0.0400	+2.0%
Transformer capacity	\$/kVA/day	0.0135	0.0138	+0.0003	+2.2%
Peak charge (control period demand)	\$/kVA/day	0.4730	0.4148	-0.0582	-12.3%
Nominated maximum demand	\$/kVA/day	0.1102	0.1135	+0.0033	+3.0%
Metered maximum demand	\$/kVA/day	0.0862	0.0713	-0.0149	-17.3%
Miscellaneous					
Monthly invoice and contract charge to	\$/invoice	30.00	30.00	-	-
Failure to pay notice	\$/notice	-	50.00	+50.00	NA
Default and termination notice	\$/notice	-	100.00	+100.00	NA
Distributed generation					
Export credits					
0 - 30kW generation					
Anytime credits (without PV), or	\$/kWh	(0.0092)	(0.0037)	-0.0055	-59.8%
Anytime credits (with PV), or	\$/kWh	(0.0003)	(0.0001)	-0.0002	-66.7%
Peak period credits (with or without PV)	\$/kWh	(0.6429)	(0.2626)	-0.3803	-59.2%
30 - 750kW Control period credits					
	\$/kW/day	(0.2202)	(0.0897)	-0.1305	-59.3%
plus	\$/kVAr/day	(0.0277)	(0.0295)	+0.0018	+6.5%
Generation credits					
500 - 1200kW Generation period	\$/kWh	(0.5000)	-	-0.5000	-100.0%

Appendix B - Electricity Authority pricing principles and information disclosure guidelines, and Commerce Commission Information disclosure requirements

Introduction

This appendix outlines and comments on the aspects of this methodology that relate to the regulatory requirements of the Electricity Authority (the “Authority”) and the Commerce Commission (the “Commission”).

The then Electricity Commission published a set of pricing principles in February 2010, together with information disclosure guidelines. The principles-based approach to distribution pricing, as we interpret it, encourages all distributors to conduct their pricing in a similar way, while the disclosure guidelines allow interested parties to see the extent to which this is happening. The Authority inherited these guidelines on its establishment in November 2010.

Under the guidelines distributors are to prepare and disclose a statement of the alignment of their pricing with the principles. The Authority will then review these disclosures with a view to informing further work in this area.

The Authority retained Concept Consulting to carry out a preliminary review of a subset of (nine) distributor pricing methodologies in 2011. As a result, some criteria and additional information requirements were proposed and consulted on by the Authority in October 2011, but no changes to the principles and guidelines were made as a result. We have reflected *some* of Concept’s comments and suggestions in our methodology.

Then, in December 2013, Castalia completed an Authority-commissioned review of distributors’ pricing methodologies against the principles and guidelines.¹⁶

Some of Castalia’s findings and suggestions have been reflected in changes to our methodology. Moreover we endorse Castalia’s recommendations as to the appropriateness of principles-based regulation and its suggestions to the Authority on ways that the regime might be improved.¹⁷ We also acknowledge both the importance and difficulty of engaging with customers over pricing, although in our view it is consultation as part of asset management planning that is more important to pricing, as it is primarily by that means that material changes to our costs can be achieved – via different investment and maintenance decisions – and it is only by *changing* our costs in some fundamental way that there can be a material effect on our prices. In a steady state situation by contrast – with normal maintenance and normal growth related capital expenditure – there is no reason to suppose any strong relationship between asset management planning and pricing.

There are some areas of Castalia’s reports that need further discussion as the benefits of some of the recommendations are not clear to us.

In terms of its summary paper, for example:

¹⁶ Castalia’s review of our 2013/14 methodology can be found on the Authority’s website: <http://www.ea.govt.nz/dmsdocument/16296>.

¹⁷ In Castalia’s summary report covering its reviews of all distributor methodologies and available at: <http://www.ea.govt.nz/dmsdocument/16276>. As of January 2016 the Authority had not formally responded to Castalia’s report.

- it recommends “Better integrating asset management (AMP) processes and pricing”. Our LRAIC approach currently integrates the two processes by signalling the economic cost of new investment in an average sense. In our view it is not practical in the vast majority of cases to try and link asset management and investment activity (which is inherently lumpy and localised) with pricing. Any attempt to do so would likely lead to price volatility over time, and very different price signals in different parts of the network. We consider that such price signals serve no useful economic purpose as they are likely to confuse most customers.¹⁸ Such signals would also likely be poorly received by retailers who could reasonably argue that they are not consistent with principles (d) and (e).
- it states that “It is common for distributors to set prices for industrial and commercial customers close to incremental cost...”¹⁹ and price higher to other, for example residential, customers. We cannot speak for other distributors, but Orion does not do this. Castalia does not state the basis for its conclusion that this is “common”.

In terms of its report on Orion’s methodology:

- Castalia says that our peak demand pricing is not linked to local network constraints, and that we do not present information on “service capacity at different areas of the network”²⁰. Our peak pricing is not trying to manage local constraints and so we have clarified our approach in the relevant sections of the methodology.
- Castalia correctly notes that we did not provide estimates of standalone cost.²¹ We do not often see by-pass (there has been no case in the past ten years at least). To us this demonstrates that it is indeed uneconomic in most cases, but we are happy to consider any claim / threat on a case-by-case basis.²²
- for similar reasons we think it is not very useful for distributors to establish with any precision that prices are “subsidy-free” given the very wide range between incremental cost (usually around zero) and standalone cost, and in particular the observed non-incidence of by-pass.²³ However, we include some additional comments on standalone costs in the pricing principles section below.

¹⁸ We also note that the current transmission pricing methodology, while not without its critics, explicitly de-links the interconnection price (which is nationwide or ‘postage stamp’) from the individual investments that drive it, and that is with respect to only a few, relatively well informed and motivated Transpower customers.

¹⁹ On page 28 of its summary report.

²⁰ Castalia review of Orion’s methodology, Table 2, p5.

²¹ Ibid.

²² We do observe that a number of larger customers use diesel generation as emergency back-up, but that none of these go the extra step and use diesel as an alternative to network connection. We take this as further indirect evidence that the all-in cost of network connection is lower than standalone cost, and given a marginal (fuel) cost of around 50 cents per kWh this is understandable.

²³ And we note Castalia’s comment on p29 of its summary report that: “However, as discussed above (under principle a(i)), cross-subsidies will be very rare in a largely fixed cost business like electricity distribution.”

- Castalia states that “Orion does not provide any forecasts of investment needs.” and it is true that there are none in this methodology. There are forecasts in our asset management plan, and we think that is the appropriate place for them. As noted above, we do not agree with Castalia that it is useful or practical to try and closely link asset management planning with pricing in any detailed sense, and we think this idea needs further discussion. We consider that LRAIC signals the cost of investment in a generic sense, so that investment that is needed will occur when customers have indicated willingness to pay for it.

More generally, we note that information on pricing is contained in a number of documents, each targeted at different levels of knowledge, understanding and interest. We are considering how best to explain to customers that suite of information and where they can find what is relevant to their needs.

Separately, in 2012, the Authority consulted on a proposed “Economic and decision-making framework for distribution pricing methodology review”, and the Authority has since promulgated this framework. We are unsure how the Authority intends distributors to apply the framework, but since the principles and guidelines are held to be consistent with it, we see the principles and guidelines as being the relevant regulatory instrument.

In addition to the Authority’s approach, the Commission, in October 2012, promulgated its own information disclosure requirements related to pricing. These reference the Authority’s principles, but also include additional requirements of our methodology. There is some overlap in the two approaches.

As this methodology was being finalised the Authority was consulting on changes to the pricing principles and the wider regulatory framework for distribution pricing. That consultation occurred too late to be reflected in this document.

Electricity Authority pricing principles

The following are the published Authority principles and, below each, a comment on our alignment:

Signal economic costs

- (a) *Prices are to signal the economic costs of service provision, by:*
- 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;*
 - having regard, to the extent practicable, to the level of available service capacity; and*
 - signalling, to the extent practicable, the impact of additional usage on future investment costs.*

In line with these principles we price to reflect the economic costs of providing our delivery service. We estimate the long run average incremental cost (LRAIC) of investment in our network (see Appendix E for more detail) and we set a peak load based price which reflects this. The fact that we must apply other additional price components (over and above the component that reflects the LRAIC) shows that our prices are greater than incremental costs (meeting the first “subsidy free” requirement in principle (a)i). Equally, prices are demonstrably lower than stand-alone costs on the basis that we provide a shared delivery service, is sized to meet the diversified load of customers, which is much smaller than the sum of individual load peaks. For example, we observe that the average residential customer peak of 7.4 kW, but when looking at an entire residential suburb, the network peak equates to just 2.3 kW per household. An alternative approach to the assessment of stand-alone costs is also set out in the paragraphs below.

The LRAIC that we estimate is both a long-run and a network-wide value. This is not to suggest that the network is everywhere equally constrained or equally close to capacity limits in the shorter term. Rather, it reflects our intention to provide a long-term price signal against which customers (or retailers or third parties) can invest in demand-side alternatives wherever they are on the network. By maintaining this incentive over the entire network and the long-term we help ensure that the demand response will be consistent and so can be assumed in our network design and planning. In this way we believe we align with principle (a) ii. But, for the avoidance of doubt, we *are not* trying to use prices to manage demand in the short term with respect to local constraints.

Because the peak pricing reflects our assessment of LRAIC, any customer who reduces demand at peak times (be it by generation and / or load reduction) effectively reduces their costs by LRAIC. Since they will presumably only do this up to the point where it is at a cost lower than LRAIC, Orion will only build more network when customers have shown, collectively, that they are willing to pay for it at a price higher than that of the alternatives (aligning with principle (a) iii).

Within our cost allocation we weight the allocation of assets that are installed for security of supply using the value that customers place on “lost load”. This helps us reflect the different willingness to pay for these back-up assets between different connection categories. We also provide a specific rebate scheme for irrigation customers that elect to be first off following a capacity constraint caused by damage to or failure of our network.

We allocate Transpower’s interconnection charges to each connection category based on our assessment of each category’s use of the transmission system. Our distribution network load is characterised by summer (rural) and winter (urban) seasonal peaks. To the level of the lower summer peak, the transmission system is in place to meet both seasonal loads, and it would not be reasonable to view either winter or summer loads as “free” marginal additional loads. So, to the extent that all connection categories use the transmission service, we have split the costs equally between summer and winter peak demands. We then allocate the additional cost of meeting the higher winter peak only to connection categories that contribute to the winter peak. As a result, our price structure to customers carries a lower winter demand price than Transpower applies to us, but provides a more equitable and stable structure.

With respect to principle a (i) as regards “subsidies”, we note that the low fixed charge regulations do mean that the proportion of our charges that apply to energy volumes is

probably higher than ideal, with the result that the savings that accrue to investment in technologies such as PV are probably overstated, and this may be leading to over-investment in PV to New Zealand's detriment. While this is not technically bypass (PV does not really support "standalone") the regulations also lead to customers with PV contributing materially less to our common costs than do otherwise equivalent customers.

More generally, we have noted other's estimates of standalone costs. For example, Powerco has provided a reference to and used an MBIE ²⁴ (MED at the time) commissioned publication²⁵ that shows a range of cost estimates for PV systems on a levelised cost of energy basis. These costs are comparable with the *retail* prices that customers pay, since a standalone customer avoids not just delivery, but energy and at least some other retail costs that come with grid connection as well.

The following table shows how these standalone cost estimates compare with estimated retail costs for the main Orion connection categories. Note that we have:

- chosen the "off-grid" scenario, which seems most appropriate for the standalone case,
- used the values for the last year, 2035, these being the lowest values, and
- chosen Dunedin as being the location most comparable with central Canterbury.

Connection category	Estimated retail cost ²⁶ (cents per kWh)	Standalone cost (cents per kWh)
Streetlighting	22.40	90
General	28.40	90
Major	14.40	90
Irrigation	19.60	90

Innovation may of course drive down the standalone cost over time.

Other costs

- (b) *Where prices 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.*

²⁴ In their *Electricity pricing methodology 2018*, pp49-50.

²⁵ *Assessment of the Future Costs and Performance of Solar Photovoltaic Technologies in New Zealand*, IT Power Australia, 2009. The website link is: <https://www.mbie.govt.nz/dmsdocument/2826-assessment-of-the-future-costs-performance-of-solar-pdf>. Table 8.1 on page 67 is the source of the numbers used here. These are 2008 \$, but we have not tried to adjust them for either inflation or exchange rates. If anything, this understates them.

²⁶ For General connections we have used the MBIE QSDP results for Christchurch for August 2018. For other categories we have added 10 cents per kWh energy cost to the variabilised delivery cost for each category using the revenues and volumes above.

The LRAIC-based component of our pricing does not recover allowed revenue. We set volume prices for general connections, and maximum demand based prices for major customers, to collect the balance of our revenue requirement. Our high volume price during weekdays (7am to 9pm) is less avoidable than consumption during nights and weekends. The low fixed charge regulations are a material constraint in this area, but we consider that keeping our off-peak volume prices very low is more efficient than having a single flat rate at all times as it supports customer choices such as 'night-rate' water heating.

Our capacity charge for major customers is based on the customer's own peak, which is less subject to demand response than other measures.

Tailored pricing

- (c) Provided that prices satisfy (a) above, prices should be responsive to the requirements and circumstances of stakeholders in order to:*
- i. discourage uneconomic bypass;*
 - ii. allow for negotiation to better reflect the economic value of services and enable stakeholders to make price/quality trade-offs or non-standard arrangement for services; and*
 - 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.*

Orion may recognise an alternative opportunity available to a major customer in close proximity to a grid exit point and may reduce the chargeable demands to approximate the lower than average cost to distribute over the shorter distance. This adjustment discourages uneconomic bypass - principle (c) i.

Customers in our major customer price category have the option to utilise additional connection equipment and back up supply connection points (which are recognised in our pricing) where they wish to receive an enhanced level of service.

In some cases we individually negotiate the pricing and charge structure directly with the customer. This is because some large capacity connections can impact on the network to which they connect such that significant additional investment by Orion is required. Such cases also provide the opportunity to tailor the quality of the service to the specific needs of the customer. We usually devise individual pricing in such cases, in line with principle (c) ii. This is not a necessary approach for most connections and would be impractical for our smaller customers.

All customers are free to invest in ways of achieving a *higher* quality service than that provided by our network, and for example:

- a number of larger customers have on-site backup generation capacity to achieve higher reliability than that provided by our network, and
- other customers invest in relatively low cost UPS devices (uninterruptible power supplies) for their critical loads, such as computers and cash registers.

Because our peak / control period prices signal the LRAIC of network investment, customers have a clear value against which to assess network alternatives. Many customers, particularly major customers, turn on generators, reduce demand or both in response to our pricing. Tens of thousands of residential customers heat their hot water only at night in response to the very low delivery cost which is generally preserved in retailers' rebundling of Orion's pricing.

More specifically, Orion offers export credits to encourage investment in and operation of generators that reliably export onto our network to provide an economical alternative to electricity delivery during peak demand times. This aligns with principle (c) iii.

Overall though, when prices are cost-reflective, we do not need to be experts in demand side management solutions and technologies. Instead, our pricing inherently rewards any party that elects to invest and innovate in response, creating a basis for choice. We do not consider there is anything wrong with building more network if that is what customers efficiently choose. Rather, we seek to ensure new network is built when it is the best way of meeting customers' energy delivery needs as revealed by those customers' preferences and willingness to pay. Put another way, there is no *single set* of observable outcomes we would expect to see in terms of customer behaviour that would allow us to conclude that our pricing 'works' as well as it possibly can, and by definition there is no counterfactual in place that we can compare against. We do observe various forms and levels of customer response, and consider that it is reasonable to assert that these are consistent with our pricing.

Stability and transparency

(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.

Orion openly discloses its pricing methodology and actively works to promote a stable and long term pricing basis, recognising in particular that customers make investments in response to our pricing:

- i. our structure for major customers has been in place for more than 20 years while our general connection pricing is essentially unchanged since its inception in 1999;
- ii. any significant changes are widely consulted on, and only made where we consider they will improve economic outcomes;
- iii. material cost allocation changes are spread over a number of years to ease the impact on customers; and
- iv. longer-term price indications are provided to customers and retailers.

In addition to this methodology document we publish a plain English network pricing guide. Our asset management plan sets out our longer term plans for the network and this includes indications of key cost drivers. We conduct twice-yearly major customer seminars at which pricing and other matters are discussed.

Complexity

(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.

Orion applies 'GXP billing' for most connections where charges are based on electricity volumes injected into the Orion network (principally at Transpower grid exit points). The

chargeable quantities for most connections therefore use the results of the wholesale market energy reconciliation process, which is itself governed by the Electricity Industry Participation Code. This provides administrative efficiencies that are reflected in our costs. Orion has relatively few connection categories (and 99% of connections are “general” connections) and there are relatively few prices within each category.

Pricing development is primarily focussed on achieving efficient outcomes for the long-term benefit of customers, but where possible we reduce retailer costs. In recent years we have introduced a range of changes to simplify the application of our pricing.

In 2009 we:

- moved from kVA to kW charging for general connection peak periods, removing the need for both Orion and retailers to carry out what can be time-consuming and error-prone calculations;
- introduced an irrigation connection category which removed the need for retailers to calculate an annual wash-up;
- reduced the number of pricing zones within our network from two to one;
- simplified the structure of our loss factors so that there were only 4 where there were previously 24;
- spread the recovery of our peak period charges over twelve months rather than six, which smoothed retailer cash flows.

In 2010 we:

- aligned the “working week day” period for general and major customers;
- aligned the general peak period and major control period seasons, which also allowed us to reduce the number of months that we must estimate general peak period demands;
- moved to use standard half-hour metering for major customers (removing the requirement for special control period metering).

In 2013 we:

- further simplified the structure of our loss factors so that, for the vast majority of connections, one of only two applies. (We also created specific loss factors for our two largest rural connections.)

In 2016 we:

- removed the split between distribution and transmission prices to publish and apply just the total delivery price;
- removed the public holiday distinction;
- rationalised dedicated equipment pricing from 45 items to 5 items;
- for major customers, replaced our assessed capacity approach with a combination of nominated maximum demand and metered maximum demand.

In 2017 we:

- consistent with broader moves to standardisation, expressed all prices in dollars (had been a combination of dollars and cents).

In 2018 we:

- rebalanced the components of our major customer pricing.

This year we:

- implemented a 15 cents per day fixed charge for general connections, and
- further rebalanced the components of our major customer pricing.

Electricity Authority information disclosure guidelines

This section directs the reader to the relevant section of the body of our methodology document, and provides additional comment where appropriate.

(a) Prices should be based on a well-defined, clearly explained and published methodology, with any material revisions to the methodology notified and clearly marked.

This methodology document constitutes the first part of the above. Where material changes are made a marked-up version could be made available, although any such changes will have been signalled and consulted on well in advance.

(b) The pricing methodology should demonstrate:

(i) how the methodology links to the pricing principles and any non-compliance

See the assessment section above.

(ii) the rationale for the consumer groupings and the method for determining the allocation of consumers to the consumer groupings

See section 4.

(iii) quantification of key components of costs and revenues;

See sections 5 and 6.

(iv) an explanation of the cost allocation methodology and the rationale for the allocation to each consumer grouping;

See sections 4, 5 and 6 and Appendix D.

(v) an explanation of the derivation of the tariffs to be charged to each consumer group and the rationale for the tariff design; and

See section 7.

(vi) pricing arrangements that will be used to share the value of any deferral of investment in distribution and transmission assets, with the investors in alternatives such as distributed generation or load management, where alternatives are practicable and where network economics warrant.

See comments above under principle (a).

Also, we directly provide the opportunity for investors to provide alternatives to planned network reinforcement by publishing the planned projects and identifying the value of deferment in our asset management plan.

(c) The pricing methodology should:

(i) employ industry standard terminology, where possible; and

We consider that we use standard terminology, and in any case we seek to explain the technical terms that we use.

(ii) where a change to the previous pricing methodology is implemented, describe the impact on consumer classes and the transition arrangements implemented to introduce the new methodology.

Where changes are contemplated we consult with affected parties over a period of time. Our consultation material provides information on the impact on customers and we evaluate transitional arrangements as part of the process. We consider that our methodology document appropriately captures the result of our consulted changes. We avoid the added complexity of repeating the description of previous provisions and transitional arrangements within our published methodology.

Commerce Commission information disclosure requirements

This section describes in a tabular format how this methodology document addresses key elements of the Commission's information disclosure requirements. Some of this information is included in the body of this methodology document above.

The relevant sections of the determination are 2.4.1 to 2.4.5.

IDD Section	Description of how addressed in this document
2.4.1 (1)	See sections 1 to 3.
2.4.1 (2)	See sections 6.11, 7.7 and Appendix A.
2.4.1 (3)	See sections 4.5 and 7.6 for non-standard contracts. See section 8 for distributed generation.
2.4.1 (4)	See section 2.7.
2.4.2	The methodology is publicly disclosed before the end of February each year for prices that apply from 1 April each year.
2.4.3 (1)	See sections 4, 5 and 7.
2.4.3 (2)	See the first part of this Appendix B.
2.4.3 (3)	See sections 5, 6 and 7.
2.4.3 (4)	See section 5.
2.4.3 (5) (a) & (b)	See section 4.
2.4.3 (6)	See section 7.7.
2.4.3 (7)	See section 6.
2.4.3 (8)	See section 7. This shows amounts rather than proportions.
2.4.4 (1) to (3)	See section 3.2 and Appendix C.
2.4.5 (1) (a) to (c)	See section 4.5 and 7.6.
2.4.5 (2) (a) & (b)	See section 4.5.
2.4.5 (3) (a) & (b)	See section 8 and the price schedules.

Appendix C - Possible future pricing changes

This appendix expands on the discussion in sections 2.8, 3.2 and appendix B above and sets out Orion's current plans with respect to possible future pricing changes. This is primarily in response to the expectations set by the Authority that distributors should set out their plans for any such changes at six-monthly intervals. We believe this methodology document is the best place for annual updates of these plans to be set out. We separately provide updates between the annual updates.

The Authority's expectations were explained and set out in November 2016 as follows:²⁷

We will continue to facilitate the industry-led approach and intend to:

- *Monitor and report on distributor progress towards adopting efficient distribution price structures.*
- *Review the current distribution pricing principles and associated information disclosure guidelines and consult on any proposed changes.*
- *Assess alignment of distributor prices against the distribution pricing principles (each year from April 2018).*

We expect industry participants to continue to progress their work. Specifically, our expectations are that:

- *The ENA will continue to lead the development of more efficient pricing. We note the ENA will shortly release its New Pricing Options for Electricity Distributors consultation paper.*
- *Before 1 April 2017, each distributor will have published its plan for introducing efficient pricing. The purpose of setting a timeframe is to encourage distributors to communicate their intentions and to make progress. Information that we would expect to see in these plans includes:*
 - *a clear outline of the process each distributor will adopt, including the nature of their planned consultation with retailers and consumers*
 - *a timeline with the key milestones*
 - *resourcing implications, including how resources will be allocated to the process of moving towards efficient pricing structures.*

Submissions on the ENA (Electricity Networks Association) paper²⁸ referred to closed in December 2016. The ENA then issued a final guidance document focussing on five approaches.

The ENA document was a key input to our own consultation in August 2017.

²⁷ See: <http://www.ea.govt.nz/development/work-programme/evolving-tech-business/distribution-pricing-review/development/next-steps-in-distribution-pricing-review/>. We note that at the time that this methodology was being finalised, the Authority was consulting on changes to the pricing principles and the way distributors' pricing approaches, and changes to those approaches, are to be assessed. We have not reflected that consultation in this methodology.

²⁸ Available at: <http://ena.org.nz/wp-content/uploads/2016/11/New-Pricing-Options-technical-discussion-paper.pdf>.

Since then we have been actively involved in the ENA's work, while continuing our own consultations.

The various consultation documents are available on our website.

Process

In terms of process, normally our annual pricing changes are relatively routine, and we would normally consult primarily with retailers. We consider that retailers remain the key stakeholders. However, the sorts of changes contemplated by the Authority, and some of the options considered by the ENA paper, potentially represent a fundamental shift in approach, with potentially significant impacts across the customer base. For that reason we believe we must undertake consumer consultation.

We have now completed some preliminary consultation primarily focused on the re-distributional consequences of volume-based charges when supply costs are largely fixed.

We anticipate further rounds of stakeholder consultation.²⁹

Timeline

Because the size of the task is not yet known, we do not yet have a detailed timeline and milestones. However, we believe the following are key considerations:

- Changes to regulation under Part 4 of the Commerce Act that will apply to the next DPP reset – that is, from 1 April 2020. Of particular relevance is change in the form of control from a weighted average price cap to a revenue cap.
- The final form of the TPM guidelines issued by the Authority, and how this manifests in the actual TPM developed by Transpower. We doubt the latter will be effective before April 2020, and it could be a year or two (from now) before the form and implications of the new TPM are sufficiently well developed for their impact on our own pricing development to be clear.
- The Authority's review of the distribution pricing principles and wider regulatory framework for distribution pricing, currently out for consultation.
- The Authority's changes to Part 6 of the Code (relating to the avoided cost of transmission) which, in Orion's case, come into effect from 1 October 2019.
- The extent of necessary consultation could be considerable.
- The knowledge that many other distributors will be making pricing changes at the same time. We need to keep abreast of these wider developments.

Resourcing

There are two key resourcing considerations:

- The relatively narrow consideration of how the pricing consultation and development is resourced. At this stage we expect this to be largely internal, although there may be some use of third parties for consumer consultation, and for external peer review. We also note that the ENA is leading and coordinating pricing reform activity across its membership. Availability of internal resources will be influenced by other Authority workstreams, for example its decisions on a default distributor agreement.

²⁹ In any consultation we will use the Authority's consultation guidance as a key reference:
<http://www.ea.govt.nz/dmsdocument/13342>

- The wider consideration of how broader business impacts are accommodated. Some possible pricing developments would likely require the development of new business processes and systems, with attendant time and costs. The materiality of such costs could raise the issue of how they can be recovered under Part 4.

Taken together, all of these considerations suggest that we are unlikely to implement material changes to our pricing before April 2020, although we may decide on what the changes are before then. Depending on the magnitude of the changes, they may be phased in over a number of years.

Our current and emerging views on pricing reform

While it is too early to say what sort of changes we will make to our pricing, we are able to provide our current and emerging views.

As we see it, the Authority's principal concern with current distribution pricing is that it is too much consumption (kWh) based. As a consequence, customers may be over-investing in technologies that reduce consumption, such as solar photo-voltaic panels. This is because they see value in reducing consumption when the retail price is, say, 25 cents per kilowatt-hour while the actual economic saving is typically less than 10 cents per kilowatt-hour.

As discussed in appendix B above, a significant proportion (roughly half) of Orion's revenue comes from consumption based charges, although these are 'TOU', not flat rate. We have this charge structure for a number of reasons, but a key one is compliance with the low fixed charge (LFC) regulations.³⁰

The Authority's recent guidance on how it will assess compliance with the regulations was an interesting development. From our work with the Authority, via the ENA, we have formed the view that the guidance is, in the end, not helpful.

We remain concerned that implementing changes that the Authority deems to be compliant will, in response to public pressure, lead to the regulations being changed so that such pricing changes become non-compliant with the changes then needing to be reversed.

The government's electricity price review has sought views on the regulations, and submissions have generally favoured their revocation. We acknowledge this would be a major step for the review to recommend and even more so for any government to implement. But without that clear support from the top, it is unreasonable to expect regulated parties to seek some sort of workaround. We appreciate that, if the regulations are revoked, that some form of phase out will be required. We are happy to explore options with officials.

More generally though, there is some risk that a focus on capacity, even if accepted by customers, has undesirable side-effects, such as:

- Customers may seek to reduce their capacity when no supply cost reduction results from their doing so. This is not in principle different to the Authority's concern about consumer response to consumption-based pricing. The nature of electricity networks is that there is very significant diversity in electrical loadings for most types of customers. For example, the average anytime maximum demand (AMD) of residential customers on the Orion network is (at 7 to 8kW), 3 to 4 times greater than their average coincident maximum demand (CMD) of 2 to 3 kW.³¹ This high diversity factor

³⁰ This discussion focusses on our 'general' connections category which encompasses all residential customers as well as most small and medium sized businesses.

³¹ This analysis uses interval data from a sample of around 2,200 (out of around 160,000) residential connections. These demands are averages measured over the half-hour intervals. Instantaneous maximum demands would usually materially exceed - and by definition cannot be less than - these values.

allows transmission and distribution networks to be built largely based on CMD, while still being able to support much higher AMDs close to connections. In fact, higher AMDs can support lower CMDs as well by enabling greater use of energy off-peak. This already happens with customers on “day/night” pricing.

- It may lead customers to believe they have a ‘right’ to whatever the nominated capacity is, when the upstream networks, which are, efficiently, built to support CMD, cannot handle this. This is an area where the telecommunications / broadband analogy falls down. With telecommunications, higher coincident demands can be managed via reductions in connection speed for all. The electrical equivalent is voltage, which for regulatory and safety reasons cannot be reduced materially. (The analogy is also poor as telecommunications providers are not required to offer a continuous set of offers of connection speeds. The Authority’s LFC guidance implies that distributors are.)

These are not reasons to not make changes, just examples of why caution is needed.

As well as the Authority’s concerns about consumption-based charges, retailers³² have for many years expressed concerns about the other key component of our pricing, the peak demand component. This component uses a demand measure based on coincident demands during our dynamically signalled peak periods, which occur in winter. It involves estimation and wash-ups, and, to the extent that retailers rebundle it into consumption-based prices it involves some risk. Any move away from this form of pricing that addresses retailer concerns is likely to compromise economic efficiency. We will thus be particularly interested in the Authority’s review (current at the time this methodology was being finalised) of the pricing principles as they address the trade-off between efficiency and simplicity. We note Castalia in its 2013 report specifically identified that the principles do require consideration of trade-offs in their application, but that, as currently written, the principles provide little guidance in this area.

Our own (2017) consultation and feedback on it has re-confirmed retailer concerns about the complexity of our current approach to peak pricing. Because we believe that most forms of so-called TOU pricing are inconsistent with our approach to load management, we have proposed progressing analysis of two alternative pricing approaches:

- one that provides for explicit rebates or credits where customers choose to allow us to manage elements of their load, and
- dynamically signalled but volume-based peak pricing, perhaps with a ‘reward’ price that would give back credits when the dynamically signalled duration exceeds some level.

In our 2018 consultation we sought to further explain our concerns about the ability of TOU pricing to deliver efficient outcomes.

The Authority’s TPM work is also relevant. While, under the most recent proposal, much of the detail is to be left to Transpower, it is clear that the Authority sees that the majority of transmission charges should be either unavoidable or difficult to avoid. While this is fairly orthodox network economics in relation to recovery of common cost elements, it is difficult to see how it squares with the low fixed charge regulations or guidelines. This reinforces our view that the revocation of the regulations is necessary for introducing cost reflective pricing.

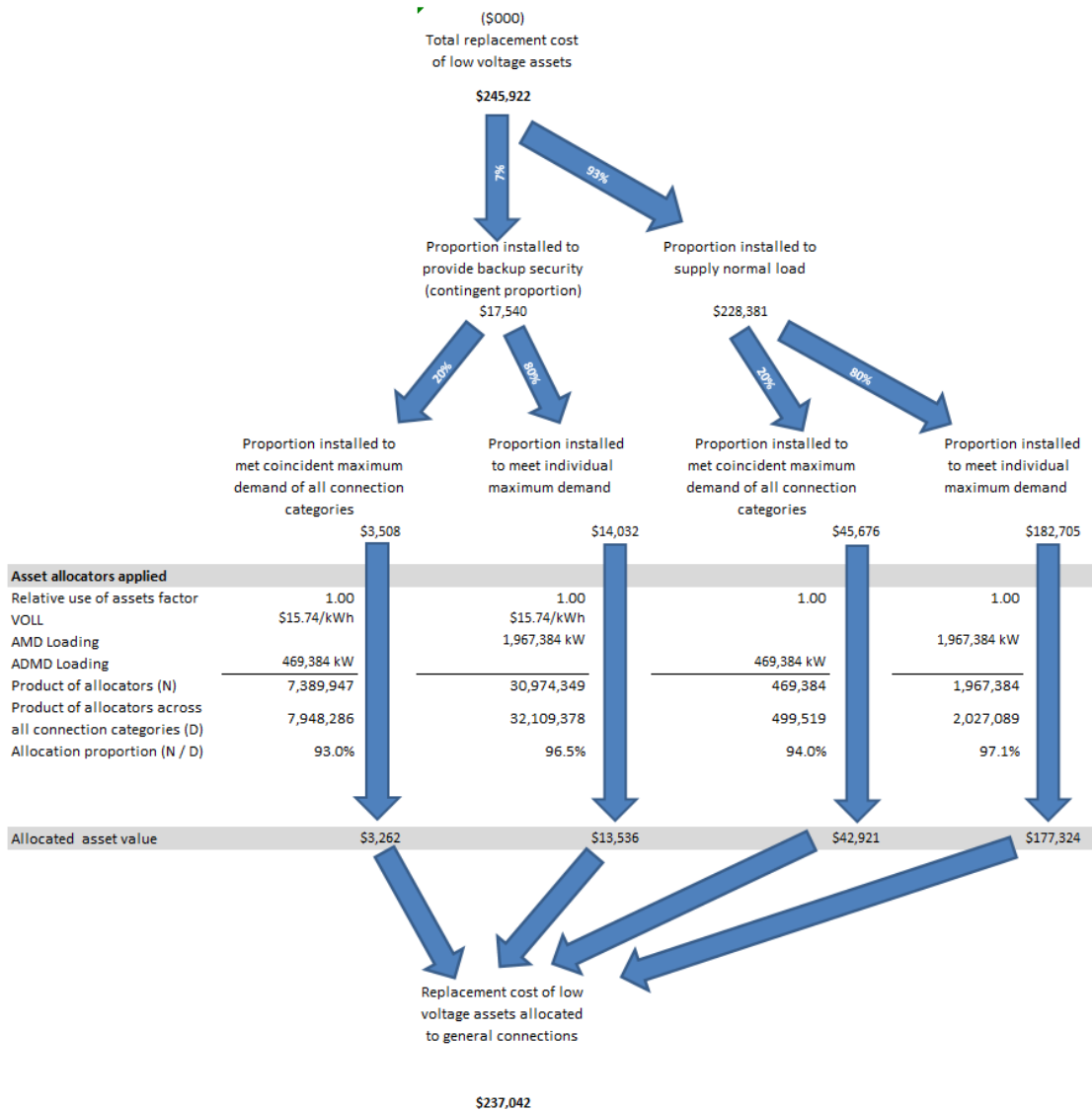
³² Not all retailers have the same views, but we consider it is accurate to say this is the predominant view among retailers, both the large and established and the new entrants.

Appendix D - Asset allocation example

Example calculation

Asset allocation for low voltage assets to general connections

(based on replacement cost established in last regulatory ODV valuation)



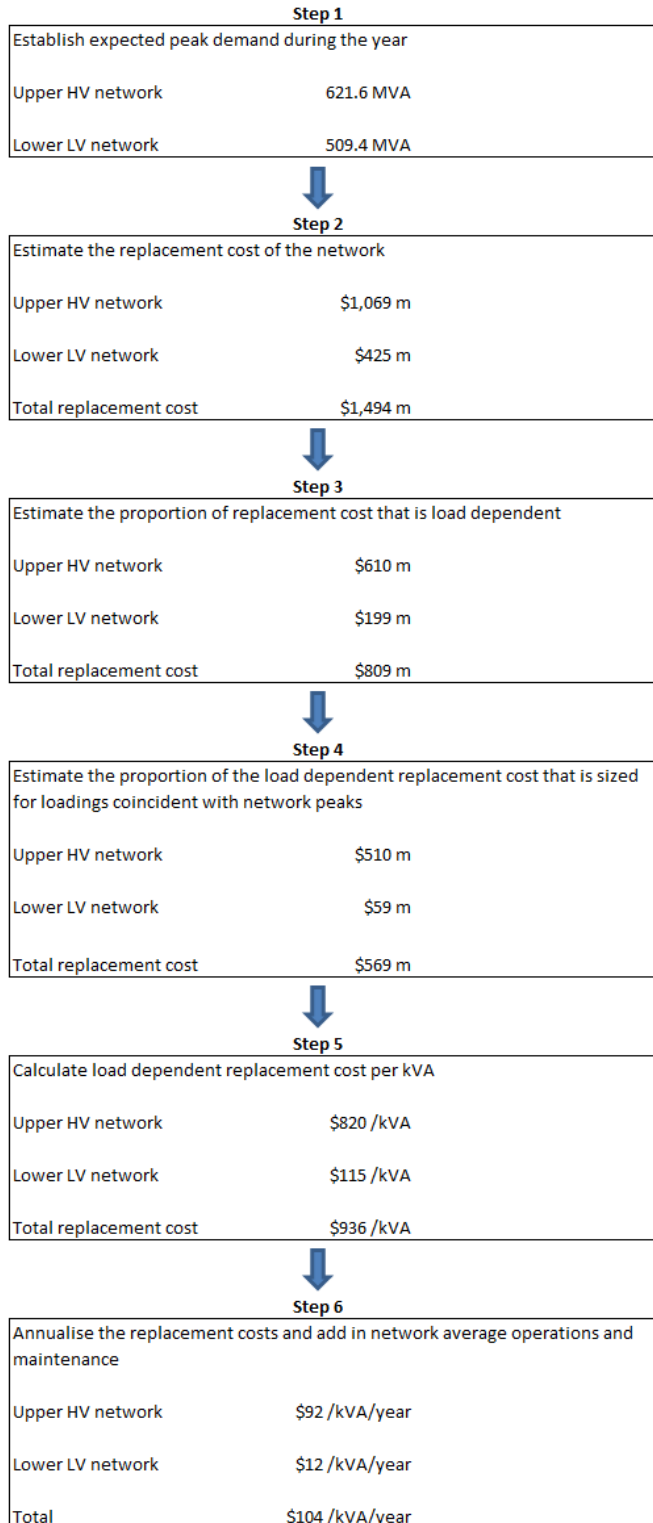
Appendix E - Derivation of LRAIC

Appendix G

Derivation of Long Run Average Incremental Cost

Orion derives its long run average incremental cost (LRAIC) for delivery of coincident peak load described in section 7.1 as follows:

Derivation steps



See notes for each step on next page.

Notes

Step 1

This is the combined coincident peak demand of all loads

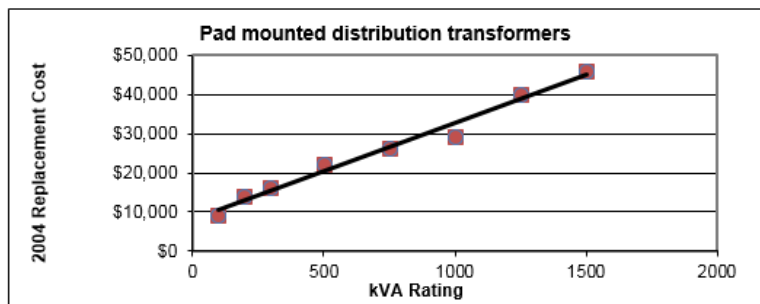
Step 2

Estimated as an average over the applicable pricing year

Upper network includes distribution transformers and above

Step 3

Individually assessed for each class of asset. For example, the cost of various size pad mounted distribution transformers shows that the fixed (load independent) cost is close to \$8000 (the y-axis intercept in the graph below), and for our installed quantities of these assets, this load independent cost equates to 48% of the total replacement cost



Step 4

This tends to be a considered engineering assessment. For example:

Asset	Network peak load dependent proportion	
Customer service fuses	Nil	While load dependent, these are sized to meet each customer's own peak load irrespective of the network peak load.
Low voltage conductors	35%	Based on the diversity between the sum of non-coincident peak demands of connections compared to that of distribution transformers.
11kV conductors	83%	Based on the diversity between the sum of non-coincident peak demands of distribution transformers compared to that of zone substations.
33kV and 66kV conductors	95%	Based on the diversity between the sum of non-coincident peak demands of zone substations compared to that of the total network.

Step 5

Simple division of load dependent replacement cost by the peak load delivered (both shown above)

Step 6

- Annualisation includes a levelised regulatory return, depreciation, taxation (including an allowance for the expected depreciation tax shield), and asset based operation and maintenance costs.
- The upper HV network has an average total life of 52.3 years while the lower LV network has an average total life of 50.3 years.
- Budgeted operations and maintenance equates to 3.4% pa of RC for the upper HV network and 3.1% for the lower LV network.
- No allowance is made for administration cost on the basis that these are not asset or load dependent.

This annual cost is reflected in our peak pricing:

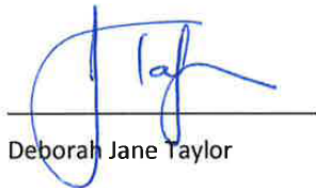
- with adjustments for the basis of charging (ie loss factor and power factor adjustments),
- smoothing the impact of changes (eg as a result of loading variability) over a number of years, and
- recognising the use of assets (in particular, major customers do not use the lower LV network)

Appendix F - Directors' certification of pricing methodology

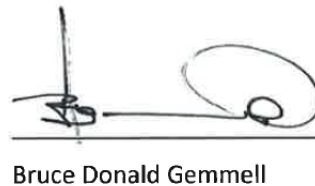
In accordance with clause 2.9.1 of section 2.9 of the Commerce Commission's information disclosure determination for electricity distribution businesses the certification of Orion's pricing methodology document is included below.

We, Deborah Jane Taylor and Bruce Donald Gemmell, being directors of Orion New Zealand Limited certify that, having made all reasonable enquiry, to the best of our knowledge:

- a) The attached information of Orion New Zealand Limited, 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.
- 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.



Deborah Jane Taylor



Bruce Donald Gemmell

Date: 22 February 2019