



# **Methodology for deriving delivery prices**

**For prices applying from 1 April 2010**

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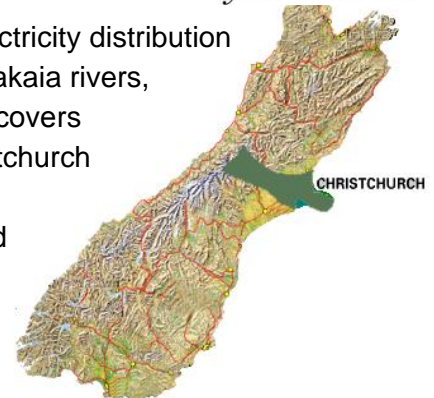
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## Methodology for deriving delivery prices



### 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 10 different locations and we distribute this electricity to more than 190,000 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 one-third 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 Pricing principles and objectives

We aim to set prices that provide sufficient revenue to cover all our costs, including pass through 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, consumers 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

Orion seeks 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

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 consumers 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.

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

### 2.2 Equitability and practicality considerations

Orion takes into account equitability 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
- recognise that all consumers should share in the benefits of greater utilisation of shared assets (and other enhanced economies of scale)
- where possible only allocate assets to the connections that use them
- recognise that consumers 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 so that the signals are effective
- set prices that are the same for all retailers, providing a level playing field to promote retail competition.

## **2.3 Regulatory considerations**

The principal regulatory requirement that we seek to comply with is that our prices must not increase by more than the price path set for us by the Commerce Commission.

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

- the Government Policy Statement on Electricity Governance (GPS), as we understand it, is indicating that rural prices should not be different to urban prices;
- the Low Fixed Charge regulations require that we provide pricing options with low fixed charges for residential consumers; and
- regulations relating to the connection of distributed generation.

## **2.4 Return on investment**

The following extract from Orion's Statement of Intent 2010–2012 sets out our approach to return on investment:

“Orion is charged with being a successful business. The benefits to the public of community ownership result from the dividends paid by the company to shareholders. The shareholding councils then use the dividends in the manner specified in their respective plans and budgets. As a provider of monopoly network delivery services, we consider that achieving a fair return on capital for that business is socially responsible and we have adopted such a policy.

In making our commercial decisions, we will act in a socially responsible way as a good corporate citizen with empathy for the communities of interest which we serve. In many of our key decisions we will continue to actively consult with customers and key stakeholders.”

### 3 Overview of our 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 consumer.

We refer to Transpower's service as *transmission*, and our service as *distribution*, and we set separate transmission and distribution prices that reflect the two distinct services. We refer to the combined transmission and distribution service as a *delivery* service.

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 and payments to embedded generators in lieu of transmission charges,
  - asset depreciation and return on capital invested,
  - operations and maintenance costs,
  - administration costs, and
  - payments to distributed generators in lieu of delivery costs.
- allocate Transpower's charges to each connection category based on our assessment of each category's use of the transmission system
- 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
- 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
- set separate transmission and distribution prices that recover the costs allocated to each category where distribution prices are expected to result in compliance with the regulatory price path<sup>1</sup>.

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<sup>1</sup> Due to the need to forecast some inputs (including transmission costs, rates and industry levies) when we set distribution prices for the year ahead which we expect to be compliant, there is a risk that assessment after the event shows non-compliance.

For the majority of our connections, we apply a 'GXP billing' approach, where in simple terms, charges are based on electricity volumes measured at a few bulk points of connection to the Transpower grid. Quantities 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.

## 4 Connection categories

We have identified situations where groups of consumers place significantly different demands on delivery assets, and situations where consumers 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

This section describes each of these categories, the rationale for maintaining the category, and the key statistics for the category.

Acronyms we use are:

- **ADMD**, for *after diversity maximum demand*. This is based on each category's contribution to the top 50 hours peak loading for the relevant season (summer or winter),
- **ΣAMD**, for *sum of anytime maximum demands*. This is the sum of a category's consumers' individual peaks (occurring at different times),
- **ODRC**, for *optimised depreciated replacement cost*. This is based on replicating the network, using modern equivalent assets and an efficient design,
- **ODV**, for *optimised deprivation value*. This is the total value of assets that allows the network to operate in an efficient, long term commercially sustainable way, and
- **RAB**, for *regulatory asset base*. This is the indexed regulatory depreciated value of assets,
- **RCPD**, for *regional coincident peak demand*. This is based on each category's contribution to Orion's peak demands that occur at the same time as the 12 highest upper South Island half-hourly demands.
- **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.

## 4.1 Streetlighting connections

Orion owns and maintains a low voltage network of lines and cables dedicated to the supply 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.

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.

<b>Assessed key statistics for streetlighting connections</b> (1 April 2010 to 31 March 2011)	<b>Forecast</b>
Number of chargeable connections	42,927 (average)
Number of ICPs	663 (average)
Energy volume	26,205 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	3,027 kW
– contribution to network-wide summer peak (ADMD)	774 kW
– contribution to upper south island peak demand (RCPD)	3,856 kW
– sum of individual connection anytime peaks ( $\Sigma$ AMD)	6,006 kW
Value of lost load (VOLL)	\$12.34 / kWh

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

## 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.

<b>Assessed key statistics for general connections</b> (1 April 2010 to 31 March 2011)	<b>Forecast</b>
Number of connections / ICPs	189,400 (average)
Energy volume	2,340,305 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	474,420 kW
– contribution to network-wide summer peak (ADMD)	306,972 kW
– contribution to upper south island peak demand (RCPD)	479,778 kW
– sum of individual connection anytime peaks ( $\Sigma$ AMD)	2,039,916 kW
Value of lost load (VOLL)	\$12.41 / kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (ie 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 applies to all connections with capacity greater than 20 kW where the primary purpose is to pump water to irrigate farmland. Orion determines whether a connection fits in this category.

<b>Assessed key statistics for irrigation connections</b> (1 April 2010 to 31 March 2011)	<b>Forecast</b>
Number of connections / ICPs	1,160 (average)
Energy volume	191,514 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	0 kW
– contribution to network-wide summer peak (ADMD)	39,682 kW
– contribution to upper south island peak demand (RCPD)	0 kW
– sum of individual connection anytime peaks ( $\Sigma$ AMD)	85,250 kW
Value of lost load (VOLL)	\$1.59 / kWh

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

### 4.4 Major customer connections

We provide a specific pricing category for our larger connections with loads that exceed 250 kVA. However:

- we do not categorise irrigation connections as major customer connections
- exporting customers with distributed generation rated in excess of 30 kW can apply to become major customer connections to take advantage of Orion's export credits
- reconciled embedded networks are 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 do not use our low voltage network
- in some cases, we do not own or maintain the transformer
- 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.

<b>Assessed key statistics for major customer connections</b> (1 April 2010 to 31 March 2011)	<b>Forecast</b>
Number of connections / ICPs	470 (average)
Energy volume	851,360 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	125,341 kW
– contribution to network-wide summer peak (ADMD)	130,697 kW
– contribution to upper south island peak demand (RCPD)	123,286 kW
– sum of individual connection anytime peaks ( $\Sigma$ AMD)	225,491 kW
Value of lost load (VOLL)	\$17.18 / kWh

Note that energy volumes and demands are expressed on a basis equivalent to grid exit measurements (ie 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.

Pricing and charge structures are individually negotiated and charged directly to the customer.

<b>Assessed key statistics for large capacity connections</b> (1 April 2010 to 31 March 2011)	<b>Forecast</b>
Number of connections / ICPs <sup>2</sup>	2
Energy volume	12,365 MWh
Peak demands	
– contribution to network-wide winter peak (ADMD)	650 kW
– contribution to network-wide summer peak (ADMD)	2,003 kW
– contribution to upper south island peak demand (RCPD)	500 kW
– sum of individual connection anytime peaks ( $\Sigma$ AMD)	3,000 kW
Value of lost load (VOLL)	\$3.50 / kWh

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

<sup>2</sup> While there are technically two connections in this category, both relate to the same customer at the same location.

## 5 Total costs

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

The disclosure requirements specify that the return on capital components within this disclosure must be based on the regulatory “ODV” value of our assets. We consider that the ODV understates the value of our assets by as much as 30% and therefore our cost of capital is understated by a similar amount.

The table below provides details of the delivery costs that we have forecast for the 2010–2011 year, which gives us our total target revenue:

<b>Cost component</b> (1 April 2010 to 31 March 2011)	<b>Forecast</b> \$000
Transpower’s interconnection charges	41,191
Transpower’s connection and new investment charges	10,230
Avoided transmission costs	590
Payments to distributed generators in lieu of transmission charges	297
<b>Transmission subtotal</b>	<b>52,308</b>
Payments to distributed generators in lieu of distribution costs	461
Administration costs	13,059
Operations and maintenance costs	36,572
Depreciation	29,359
Asset value (average regulatory asset base, \$000)	831,708
Adjusted return on capital*	5.4%
Taxation (based on standard 30% company tax rate)	19,305
<b>Distribution subtotal</b>	<b>143,801</b>
<b>Delivery total (total target revenue)</b>	<b>196,110</b>

\* we adjust and reduce our return on capital with the aim of complying with the Commerce Commission’s price path regulations.

## 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 and in particular economic efficiency, equitability and practicality.

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 (eg sub-transmission assets) is weighted more in favour of each category's contribution to network 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 ( $\Sigma$ 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 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 consistent with that from other sources which ranges between \$2 and \$40 per kilowatt hour (much higher than the normal retail cost of delivered electricity which ranges from 15¢ to 25¢ per kilowatt hour).

Our asset allocation is based on the replacement cost and detailed asset assessment contained in our latest audited valuation prepared in accordance with the Commerce Commission's optimised deprival value (ODV) methodology, prepared as at 31 March 2004.

The resulting allocations by asset category are:

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

<b>Asset category</b>	<b>Street lighting</b>	<b>General</b>	<b>Irrigation</b>	<b>Major customer</b>	<b>Large capacity*</b>	<b>Total</b>
	\$000	\$000	\$000	\$000	\$000	\$000
Subtransmission	1,244	195,278	12,257	57,264	1,831	267,874
Power Transformers	195	30,646	1,718	9,273	1,022	42,854
11kV Distribution	1,256	210,167	13,733	55,691	0	280,848
Land & Property	206	70,019	2,732	7,966	984	81,907
Distribution Transformers	300	84,227	3,969	9,594	0	98,089
Low voltage distribution	131	241,171	1,132	3,488	0	245,922
Lighting	14,577	0	0	0	0	14,577
<b>Total</b>	<b>17,908</b>	<b>831,508</b>	<b>35,539</b>	<b>143,278</b>	<b>3,837</b>	<b>1,032,070</b>

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

We then allocate our forecast average regulatory asset base (average RAB) to each category in proportion to the allocation of replacement costs. We use this method to allocate RAB 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 RAB represents the indexed regulatory depreciated value of assets averaged over the year. The resulting allocation of average RAB for each connection category is:

	<b>Street lighting</b>	<b>General</b>	<b>Irrigation</b>	<b>Major customer</b>	<b>Large capacity</b>	<b>Total</b>
	\$000	\$000	\$000	\$000	\$000	\$000
Average RAB allocation	14,431	670,082	28,640	115,462	3,092	831,708

## 6.2 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 occurs in winter and is measured over the top 12 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, we have split the costs equally between the categories in proportion to their transmission demands (using ADMD). We then allocate the additional cost of meeting the higher winter peak only to connection categories that contribute to the winter peak.

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 ( $\Sigma$ AMD).

Finally, we allocate the cost of any transmission alternatives that we procure:

- the avoided transmission investment is allocated according to  $\Sigma$ AMD as it is an alternative to connection assets.
- the transmission components of our export and generation credits reflect the savings in Transpower's charges that result from reduction in winter peak demands, and are thus allocated using ADMD.

In summary:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	\$000	\$000	\$000	\$000	\$000	\$000
Transpower's interconnection charges	184	30,069	1,354	9,495	89	41,191
Transpower's connection and new investment charges	26	8,828	369	976	31	10,230
Avoided transmission investment	2	511	21	56	0	590
Transmission component of export and generation credits	1	234	0	62	0	297
<b>Transmission cost allocation</b>	<b>213</b>	<b>39,642</b>	<b>1,745</b>	<b>10,589</b>	<b>120</b>	<b>52,308</b>

### 6.3 Distributed generation distribution cost allocation

The distribution components of our export and generation credits reflect the savings in distribution costs gained from this generation contribution. The cost reduction provided by distributed generators relate 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	General	Irrigation	Major customer	Large capacity	Total
	\$000	\$000	\$000	\$000	\$000	\$000
Distribution component of export and generation credits	2	340	28	90	0	461

### 6.4 Administration cost allocation

Costs associated with administration and overheads are not related to our assets. We allocate these costs to each connection category in proportion to the sum of individual connection anytime peaks ( $\Sigma$ AMD), as this reflects the extent to which each connection utilises our service. The resulting allocation is:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	\$000	\$000	\$000	\$000	\$000	\$000
Administration cost allocation	33	11,290	472	1,248	15	13,059

### 6.5 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	General	Irrigation	Major customer	Large capacity	Total
	\$000	\$000	\$000	\$000	\$000	\$000
Operations and maintenance cost allocation	635	29,465	1,259	5,077	136	36,572

### 6.6 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. The resulting cost allocations are:

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	\$000	\$000	\$000	\$000	\$000	\$000
Depreciation cost allocation	509	23,654	1,011	4,076	109	29,359
Adjusted return on capital (6.1%)	782	36,292	1,551	6,253	167	45,045
Taxation cost allocation	335	15,554	665	2,680	72	19,305
<b>Total cost of capital allocation</b>	<b>1,626</b>	<b>75,499</b>	<b>3,227</b>	<b>13,009</b>	<b>348</b>	<b>93,709</b>

## 6.7 Target revenue adjustments and total cost allocation

The final step in establishing the total cost allocation for each connection category is to 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 spread any significant changes in cost allocations over two to three years.

These adjustments do not represent a change to our costs or cost allocation methodology, rather, the adjustments represent a change to our return on capital for each connection category (initially applied in section 6.6 above), as noted in the table below.

Adding together each of the individual cost allocations (sections 6.2 to 6.6 above) gives our total target revenue for each connection category.

	Street lighting	General	Irrigation	Major customer	Large capacity	Total
	\$000	\$000	\$000	\$000	\$000	\$000
Transmission costs allocation	213	39,642	1,745	10,589	120	52,308
Cost adjustment	0	0	230	-230	0	0
<b>Target transmission revenue</b>	<b>213</b>	<b>39,642</b>	<b>1,975</b>	<b>10,359</b>	<b>120</b>	<b>52,308</b>
Distributed generation cost allocation	2	340	28	90	0	461
Administration cost allocation	33	11,290	472	1,248	15	13,059
Operations and maintenance cost allocation	635	29,465	1,259	5,077	136	36,572
Total cost of capital allocation	1,626	75,499	3,227	13,009	348	93,709
Cost adjustment	-1	-66	218	-150	0	0
<b>Target distribution revenue</b>	<b>2,295</b>	<b>116,528</b>	<b>5,204</b>	<b>19,274</b>	<b>500</b>	<b>143,801</b>
<b>Total target revenue</b>	<b>2,507</b>	<b>156,170</b>	<b>7,179</b>	<b>29,634</b>	<b>620</b>	<b>196,110</b>
<b>Resulting return on capital</b>	<b>5.4%</b>	<b>5.4%</b>	<b>7.0%</b>	<b>5.1%</b>	<b>5.4%</b>	<b>5.4%</b>

Note that distributed generation costs are split between transmission and distribution components

## 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 consumers can adjust their behaviour to reduce their delivery costs, and this change in behaviour provides a corresponding saving for us.

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
- derive prices that provide the total target revenue established in section 6 above.

The final derived prices are summarised in the schedules in appendix A, *Delivery prices*, *Export and generation credits*, and *Dedicated equipment prices*.

### *Customer funded assets*

We receive capital contributions toward the construction of new assets and network extensions. We account for these capital contributions as revenue and count it towards our distribution revenue requirement before setting other distribution prices. This approach avoids any double payment by consumers ensuring that we do not make a return on assets that have been provided by others.

### *Reflecting our long run costs*

A key aspect in establishing our pricing structure is to ensure that our prices are cost reflective. This supports appropriate decisions both by consumers 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 peak demand of all consumers (ADMD). We design and construct our network to meet this combined peak load. We consider that approximately 50% of our distribution costs are directly dependent on peak loading (the remainder of our costs are either fixed or dependent on the peak demand of individual consumers or groups of consumers).

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 connection categories.

## 7.1 Streetlighting connections

Energy used by streetlighting connections is subject to our general connection prices applied to GXP volumes (including peak demands). These prices provide incentives to maximise the efficiency of lights, but the revenue collected does not cover the additional cost to provide our dedicated lighting circuits.

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.

Chargeable quantity	Distribution price	Transmission price	Distribution revenue \$000	Transmission revenue \$000
<b>Capital contributions</b>				
<i>Undergrounding</i>			77	
<b>Fixed charges</b>				
<i>Daily charge</i>				
42,927 connections	10.71 ¢ / connection / day	0.07 ¢ / connection / day	1,678	11
<b>Peak charges</b>				
<i>Network wide</i>				
2,314 kW	30.66 ¢/kW/day	12.14 ¢/kW/day	259	103
<b>Volume charges</b>				
<i>Working weekdays (7am - 9pm)</i>				
3,245 MWh	4.725 ¢ / kWh	1.490 ¢ / kWh	153	48
<i>Nights, weekends and holidays</i>				
22,960 MWh	0.560 ¢ / kWh	0.225 ¢ / kWh	129	52
<b>Total revenue</b>			2,296	214
<i>compared with target revenue (from section 6.7)</i>			2,295	213

## 7.2 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 \$116 per kW per year for general connections, and hence we have set the distribution peak price very close to this at \$112 per kW per year (applied as 30.66 ¢ per kW per day).

In addition a significant proportion of Transpower's charges to us are based on peak loadings and this is reflected in the transmission peak price.

The balance of our revenue requirement for both distribution and transmission is collected through our volume charges. We have structured these charges based on volumes of energy to reflect the value of our service to each consumer, and we have applied a day/night differential to reinforce our peak based pricing incentive and encourage better utilisation of our network. Using energy volumes also supports compliance with low fixed charge regulations.

### *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.

Chargeable quantity	Distribution price	Transmission price	Distribution revenue \$000	Transmission revenue \$000
<b>Capital contributions</b>				
<i>Undergrounding</i>			1,256	
<i>Connection fees and extensions</i>			5,066	
<b>Volume charges</b>				
<i>Working weekdays (7am - 9pm)</i>				
1,063 MWh	4.725 ¢ / kWh	1.490 ¢ / kWh	50,236	15,842
<i>Nights, weekends and holidays</i>				
1,277 MWh	0.560 ¢ / kWh	0.225 ¢ / kWh	7,152	2,874
<b>Peak charges</b>				
<i>Network wide</i>				
471,907 kW	30.66 ¢/kW/day	12.14 ¢/kW/day	52,811	20,911
<b>Low power factor</b>				
<i>Low power factor charge</i>				
10 kVAr	15.00 ¢/kVAr/day	5.00 ¢/kVAr/day	1	0
<b>Total revenue</b>			116,521	39,628
<i>compared with target revenue</i> (from section 6.7)			116,528	39,642

### 7.3 Irrigation connections

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

The price structure recognises that our delivery costs are primarily driven by the relatively constant load of pump motors (measured via their capacity rating), which have very little diversity during the irrigation season, rather than their diversified combined loading. (In other words, all irrigators are generally on at the same time to around full capacity.) It also allows us to recognise this category's relatively small contribution to our winter based transmission costs.

The balance of our revenue requirement is collected based on energy volumes, as described for the general connections category in section 7.2.

#### *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 consumers 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 an emergency, and this allows us to provide a higher level of service to other consumers 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.

Chargeable quantity	Distribution price	Transmission price	Distribution revenue \$000	Transmission revenue \$000
<b>Capital contributions</b>				
<i>Connection fees and extensions</i>			646	
<b>Capacity charges</b>				
<i>Chargeable pump capacity</i>				
64,409 kW	39.02 ¢/kW/day	5.43 ¢/kW/day	4,574	637
<b>Volume charges</b>				
<i>Working weekdays (7am – 9pm)</i>				
71,679 MWh	4.275 ¢ / kWh	1.490 ¢ / kWh	339	1,068
<i>Nights, weekends and holidays</i>				
119,835 MWh	0.560 ¢ / kWh	0.255 ¢ / kWh	671	270
<b>Rebates</b>				
<i>Power factor correction</i>				
27,963 kVAr	(15.05) ¢/kVAr/day	-	(766)	-
<i>Interruptibility</i>				
37,866 kW	(3.67) ¢/kW/day	-	(259)	-
<b>Total revenue</b>			5,205	1,974
<i>compared with target revenue (from section 6.7)</i>			5,204	1975

Note that the capacity charges and the rebates apply only in the period October to March.

#### 7.4 Major customer connections

As noted above, we consider that the key cost driver in providing our delivery service is the coincident peak demand of all connections. We design and construct our network to meet this peak demand.

Our calculations support an LRAIC of \$108 per kVA per year (or 29.6¢ per kVA per day) for major customer connections and we are progressively moving our distribution price for control period demand toward this *ideal* price (note that this calculated LRAIC differs from the calculated figure for general connections because it excludes the cost of low voltage assets and is based on kVA loadings metered at the point of connection, rather than kW loadings measured at the GXP).

We also provide some dedicated equipment for major customer connections and the prices are included in our dedicated equipment prices schedule in appendix A. This service is provided in active competition with other suppliers. We set our prices to cover all costs and reflect the competitive nature of this aspect of our service.

Finally, the fixed costs associated with managing this pricing category and processing half-hour interval metering information is reflected in our fixed charges and we recover the balance of our distribution revenue requirement through the capacity charges.

In relation to the transmission component, a significant proportion of Transpower's charges to us are based on peak loadings and this is reflected in the transmission price for control period demand. We recover the balance of the transmission allocation via capacity prices that are applied to consumers' anytime maximum demands (as measured by their assessed capacities).

Chargeable quantity	Distribution price	Transmission price	Distribution revenue \$000	Transmission revenue \$000
<b>Capital contributions</b>				
<i>Extensions</i>			387	
<b>Fixed charges</b>				
<i>Standard connections</i>				
441 connections	148.23 ¢ / connection / day	-	222	-
<i>Secondary connections</i>				
16 connections	78.89 ¢ / connection / day	-	5	-
<i>Dedicated equipment</i>			1,801	-
<b>Capacity charges</b>				
<i>Assessed capacity - distribution</i>				
214,000 kVA	6.78 ¢/kVA/day	-	5,296	-
<i>Assessed capacity - transmission</i>				
229,000 kVA	-	6.16 ¢/kVA/day	-	5,149
<b>Control period demand charges</b>				
117,00 kVA	27.07 ¢/kVA/day	12.19 ¢/kVA/day	11,560	5,206
<b>Total revenue</b>			19,271	10,355
<i>compared with target revenue</i> (from section 6.7)			19,274	10,359

## 7.5 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.

With the irregular nature and relatively significant scale of capital contributions for this category, we amortise the contribution (as delivery revenue) over the life of the asset, rather than assessing the full amount in the year received.

Pricing and charge structures are negotiated directly with the consumer and the table below only shows revenue projected for the year to 31 March 2011.

Chargeable quantity	Distribution price	Transmission price	Distribution revenue \$000	Transmission revenue \$000
<b>Capital contributions</b>				
<i>Extensions</i>			110	
<b>Distribution charges</b>			390	
<b>Transmission charges</b>				120
<b>Total revenue</b>			500	120
<i>compared with target revenue</i> (from section 6.7)			500	120

## 7.6 Revenue summary

The table below summarises the total projected revenue from both transmission and distribution charges for each of the connection categories:

	Street lighting \$000	General \$000	Irrigation \$000	Major customer \$000	Large capacity \$000	Total \$000
<b>Distribution</b>	2,296	116,521	5,205	19,271	500	143,792
<b>Transmission</b>	214	39,628	1,974	10,355	120	52,288
<b>Delivery</b>	<b>2,509</b>	<b>156,147</b>	<b>7,179</b>	<b>29,626</b>	<b>620</b>	<b>196,080</b>

## 8 Credits for export and generation

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. Separately, generators that respond to our signal at other times can also assist with capacity constraints, enhancing security of supply and service quality, and this benefit is reflected in our generation credits.

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 (export credits and generation credits) 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 sections 6.2 and 6.3 above show the assignment of these costs to connection categories.

### *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 \$116 per kW per year (as noted in section 7.2 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 often 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 to encourage appropriate levels of each.

Exporting generators also reduce our exposure to Transpower's interconnection charges if they generate during Transpower's regional coincident peak demand periods. We have assessed the extent to which generation during our signalled peak and control periods will reduce these chargeable loadings and this is reflected in the transmission component of our export credits.

### *Standard generation credit prices*

The generation credit arrangement is established to reduce loading levels via generation support at other times, and the credit is based on electricity generated, regardless of whether this is used within the connection or exported onto our network. We set the price at a level that is sufficient to attract the required level of load reduction.

### *Non-standard credit prices*

We assess non-standard credit prices for larger generation and other situations that do not meet our standard criteria. The individual prices are based on our assessment of actual (rather than average) benefits associated with the generation.

## Appendix A - Price schedules

### Delivery prices

(applicable from 1 April 2010)

(excluding GST)



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.

	Distribution	Transmission	Delivery (total)	
<b>Streetlighting connections</b> <i>approx 42,100 connections</i>				
Fixed charge	10.71	0.07	10.78	¢/conn/day
Peak charge (peak period demand)	30.66	12.14	42.80	¢/kW/day
Volume charge				
Working weekdays (7am - 9pm)	4.725	1.490	6.215	¢/kWh
Nights, weekends and holidays	0.560	0.225	0.785	¢/kWh
<b>General connections</b> <i>approx 189,400 connections</i>				
Peak charge (peak period demand)	30.66	12.14	42.80	¢/kW/day
Volume charge				
Working weekdays (7am - 9pm)	4.725	1.490	6.215	¢/kWh
Nights, weekends and holidays	0.560	0.225	0.785	¢/kWh
Low power factor charge	15.00	5.00	20.00	¢/kVAr/day
<b>Irrigation connections</b> <i>approx 1,160 connections</i>				
Capacity charge	39.02	5.43	44.45	¢/kW/day*
Volume charge				
Working weekdays (7am - 9pm)	4.725	1.490	6.215	¢/kWh
Nights, weekends and holidays	0.560	0.225	0.785	¢/kWh
Rebates				
Power factor correction rebate	(15.05)	-	(15.05)	¢/kVAr/day*
Interruptibility rebate	(3.76)	-	(3.76)	¢/kW/day*
	* applied from 1 October to 31 March only			
<b>Major customer and embedded network connections</b> <i>approx 470 connections</i>				
Fixed charge				
Fixed (standard connections)	148.23	-	148.23	¢/conn/day
Fixed (secondary connections)	78.89	-	78.89	¢/conn/day
Dedicated equipment	see separate price schedule			
Peak charge (control period demand)	27.07	12.19	39.26	¢/kVA/day
Capacity charge				
Assessed capacity distribution	6.78	-	6.78	¢/kVA/day
Assessed capacity transmission	-	6.16	6.16	¢/kVA/day
<b>Large capacity connections</b> <i>2 connections</i>				
Distribution and transmission charges	<i>individually assessed</i>			
<b>Miscellaneous</b>				
Monthly invoice charge to retailers and directly contracted customers	20.00	-	20.00	\$/invoice

#### Notes

1. Full details on how we apply these prices are included in the document *Application of delivery prices*, available on our website.
2. 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 important 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 connection.

## Export and generation credits

(applicable from 1 April 2010)



(excluding GST)

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 further details refer to the document *Application of export and generation credits*, available on our website.

### Export credit pricing

Orion provides credits for electricity exported on to Orion's network during specified periods. The prices for these credits are:

Generator output	Period applied	Distribution	Transmission	Delivery	
0 - 30kW Anytime credits <sup>2</sup>	Anytime (24 hours, 7 days)	0.657	0.410	1.067	¢/kWh
- or -					
0 - 30kW Peak period credits <sup>2</sup>	General connection chargeable peak period	38.40	24.00	62.40	¢/kWh
30 - 750kW Control period credits	Major customer control period				
- real power		57.53	35.95	93.48	\$/avg kW/yr
- reactive power		18.91	0.00	18.91	\$/avg kVAr/yr
above 750 kW	<i>Individually assessed prices provided on application</i>				

#### Notes for export credit pricing

1. Full details covering generation and metering requirements and application of prices are included in the document *Application of export and generation credits*, available on Orion's website.
2. Small 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. Approximately 19 connections are approved for export credits.

### Generation credit pricing

In addition to the credits above, Orion provides credits for generation at other times. These credits are based on the generated volume, regardless of whether this results in export from the connection, and are available to consumers with generation in excess of 30kW.

Generator output	Period applied	Distribution	Transmission	Delivery	
30 - 750kW Generation period	Orion's ripple signalled generation period	30.0	30.0	60.00	¢/kWh
Above 750 kW	<i>Individually assessed prices provided on application</i>				

#### Notes for generation credit pricing

1. Full details covering generation requirements and the application of credit prices are included in the document *Application of export and generation credits*, available on our website.
2. These prices apply for pre-approved generation during our ripple signalled generation period. The total duration of generation periods is likely to vary significantly from year to year. In some years there may be no generation periods.
3. Approximately 33 connections are approved for generation credits.

## Dedicated equipment prices

(applicable from 1 April 2010)



The prices below are applied in respect of Orion owned equipment that is permanently installed and dedicated to a major customer connection. Full details on how we apply these prices are included in the document *Application of delivery prices*, available on our website.

	<b>Price</b> €/day excluding GST
<b>Switchgear &amp; protection</b>	
11kV Circuit breakers	1,099
11kV Oil switch (fused)	241
11kV Oil switch (not fused)	139
11kV Magnefix type UT	250
11kV Magnefix type 1K2T	474
11kV Magnefix type 1K3T	647
11kV Magnefix type 2K1T	393
11kV Magnefix type 2K2T	648
11kV Magnefix type 2KBK	341
11kV Magnefix type 3K	306
11kV Magnefix type 3K1T	495
11kV Magnefix type 4K1T	622
11kV Magnefix type KB2KBK	418
11kV Magnefix type KBX	194
11kV Magnefix type KTB	275
11kV Overcurrent relays	145
11kV Air break isolators (ABI)	251
<b>Metering interface</b>	
Current transformers (3ph set)	131
Voltage transformers	341
Test blocks	5
11kV integral CT/VT unit	958
<b>Other equipment</b>	
Full kiosks	263
Half kiosks	181
11kV Underground cabling (per km)	252
11kV Overhead lines (per km)	161
<b>Distribution transformers (pole mounted)</b>	
50 kVA pole	184
100 kVA pole	274
150 kVA pole	347
<b>Distribution transformers (pad mounted)</b>	
100 kVA	371
150 kVA	408
200 kVA	481
250 kVA	527
300 kVA	572
400 kVA	708
500 kVA	842
600 kVA	952
750 kVA	1,115
750 kVA (dry)	1,516
1000 kVA	1,329
1250 kVA	1,825
1500 kVA	2,122

### Notes

1 Equipment prices include standard maintenance, replacement (at end of useful life) and component certification (where appropriate). Initial installation costs and non-recoverable assets costs are charged in addition.

2 Other services may be provided on a 'fee for service' basis by agreement.