Electricity Distribution Services
Default Price-Quality Path
Determination 2010

Default price-quality path annual compliance statement

For the year ending 31 March 2012

Issued 6 June 2012

ORION NEW ZEALAND LIMITED
200 Armagh Street, PO Box 13896, Armagh, Christchurch 8141, New Zealand
PHONE +64 3 363 9898 | FAX +64 3 363 9899 | oriongroup.co.nz

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INTRODUCTION

1 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 separate locations and we distribute this electricity to more than 192,000 homes and businesses.

2 We charge electricity retailers on a wholesale basis for this delivery service. Retailers, in turn, include this cost in their retail electricity prices - our charges typically amount to around one third of a household's electricity bill.

3 As a natural monopoly service provider, we are subject to government regulation under the Commerce Act 1986. Pursuant to the requirements of this Act, the Commerce Commission has set a default price-quality path (DPP) which applies to all non-exempt distribution businesses (including Orion).

4 The default price-quality path requirements are set out in Electricity Distribution Services Default Price-Quality Path Determination 2010. This statement has been prepared to demonstrate our compliance, or otherwise, with the requirements in this determination.

5 Specifically, this compliance statement covers the information requirements detailed in clause 11 of the determination for the year to 31 March 2012.

6 We prepared this compliance statement and issued it on 6 June 2012.

PRICE PATH STATEMENT AND QUALITY STANDARDS STATEMENT

7 This year, we **satisfied** our price path requirement, with notional revenue falling $197.7k below our allowable notional revenue of $138,270.0k, calculated in accordance with clause 8.4 of the determination.

8 This year we **breached** our reliability requirement as a result of the ongoing earthquakes. Over the last two assessment periods, the duration of our outages (calculated in accordance with clause 9.2 of the determination) lasted 78% longer and 124% longer than the requirement (in each assessment year respectively), and the number of interruptions exceeded the requirement by 60% and 144% (in each assessment year respectively).

9 Full details are included in this compliance statement.

PRICE PATH SUPPORTING INFORMATION

10 Clause 8.4 of the determination requires that notional revenue (NR_t) does not exceed allowable notional revenue (R_t) at any time during the assessment period, as expressed by the following condition:

$$\frac{NR_t}{R_t} \leq 1$$

Notional revenue

11 Using the definitions provided in clause 8.4, notional revenue is evaluated as:

$$NR_t = \sum_i P_{i,t} Q_{i,t-2} - K_t$$

where t denotes the year of the assessment date, that is 2012, and:

$$\therefore NR_{2012} = \sum_i P_{i,2012}\, Q_{i,2010} - K_{2012}$$

where $\sum_i P_{i,2012}\, Q_{i,2010}$ is the sum of each (i^{th}) price during any part of the assessment period pertaining to electricity lines services, multiplied by the corresponding quantity for 2010. This expression is evaluated as $196,918.6k in the worksheet on page 8 titled *notional revenue worksheet*, and

K_{2012} is the sum of all pass-through costs for the year to 31 March 2012. This expression is evaluated as $58,846.3k in the worksheet on page 10 titled *pass-through costs.*

$$\therefore NR_{2012} = \$196{,}918.6k - \$58{,}846.3k$$

$$= \$138{,}072.3k$$

12 Prices remained the same throughout the assessment period, so notional revenue was the same at all times during the assessment period.

Allowable notional revenue

13 Allowable notional revenue is defined in clause 8.4 as:

$$R_t = ((\sum_i P_{i,t-1}\ Q_{i,t-2} - K_{t-1}) + (R_{t-1} - NR_{t-1}))\ x\ ((1 + \Delta CPI_t)\ x\ (1 - X))$$

$$\therefore R_{2012} = ((\sum_i P_{i,2011}\ Q_{i,2010} - K_{2011}) + (R_{2011} - NR_{2011}))\ x\ ((1 + \Delta CPI_{2012})\ x\ (1 - X))$$

Where $\sum_i P_{i,2011}\ Q_{i,2010}$ is notional revenue for the previous year (2011), which is evaluated as $190,770.0k in the worksheet on page 9 titled *allowable notional revenue worksheet*, and

K_{2011} is the sum of all pass-through costs for the previous year (2011), which is evaluated as $54,792.6k in the worksheet on page 10 titled pass-through costs, and

$R_{2011} - NR_{2011}$ is the difference between allowable notional revenue and notional revenue carried forward from our previous annual compliance statement, which is $132,689.0k - $132,814.6k = ($125.6k), and

ΔCPI_{2012} is the average change in CPI (all groups index published by Statistics New Zealand) and X is the specified rate of change in prices, which is 0% for Orion.

ΔCPI_{2012} is calculated as:

$$\Delta CPI_{2012} = \frac{CPI_{Dec,2009} + CPI_{Mar,2010} + CPI_{Jun,2010} + CPI_{Sep,2010}}{CPI_{Dec,2008} + CPI_{Mar,2009} + CPI_{Jun,2009} + CPI_{Sep,2009}} - 1$$

$$= \frac{1093 + 1097 + 1099 + 1111}{1072 + 1075 + 1081 + 1095} - 1$$

$$= 1.78\%$$

Substituting these into the equation, allowable notional revenue becomes:

$$R_{2012} = (190{,}770.0k - 54{,}792.6k - 125.6k)\ x\ ((1 + 1.78\%)\ x\ (1 - 0\%))$$

$$= \$138{,}270.0k$$

14 Substituting the values calculated above in the price path condition gives:

$$\frac{NR\,2012}{R_{2012}} = \frac{\$138.072.3k}{\$138{,}270.0k} = 0.999 < 1$$

15 Our notional revenue is $197.7k less than our allowable notional revenue and, as the condition is satisfied, we comply with the price requirement specified in clause 8.4 of the determination.

16 While we satisfied the requirement, we note that actual chargeable quantities fell 10.0% short of expectations as a result of the Canterbury Earthquakes, and this had a direct and corresponding impact on our *actual* revenues. Unavoidably, this shortfall in revenue came at a time when we faced significant additional operational and capital expenses as a result of our response and recovery efforts.

17 Looking beyond our own revenue requirement, we consider that we have also been significantly disadvantaged by the default price path formula. This is because we effectively guarantee payment of Transpower's charges, and while our revenue dropped, Transpower's charges to us continued unaltered.

18 This divergence between Transpower's charges and the transmission revenue within our price has left us to pick up a shortfall of approximately $4.3m. The fact that this is not reflected in the price path assessment is, in our view, a flaw in the approach.

19 With the quantities set to a base two years prior to the actual year, we face a similar shortfall in the subsequent financial year.

20 As we submitted during consultation on the default price path, we consider that separate assessment of Transpower's charges against transmission price revenue, with an "unders and overs" account, to carry forward any under or over recovery, would have provided a simple and effective mechanism to deal with this flaw.

Notional revenue worksheet

$$NR_{2012} = \sum_i P_{i,2012}\ Q_{i,2010} - K_{2012}$$

($000)

	Quantities ($Q_{i,2010}$)		Assessed delivery prices ($P_{i,2012}$) as at 31 March 2012		Notional annual delivery charges ($P_{i,2012}$ x $Q_{i,2010}$)
Streetlighting, general and irrigation connections					
Streetlighting fixed charge	42,015.9	Connections	11.05	¢/conn/day	1,699.2
Streetlighting and general connections					
Peak charge (peak period demand)	472,588.8	kW	42.97	¢/kW/day	74,324.1
Streetlighting, general and irrigation connections volume charge					
Working weekdays (7am - 9pm)	1,144,714.8	MWh	6.546	¢/kWh	74,933.0
Nights, weekends and holidays	1,401,838.2	MWh	0.830	¢/kWh	11,635.3
General connections					
Low power factor charge	0	kVAr	20.00	¢/kVAr/day	0.0
Irrigation connections					
Capacity charge	68,609.0	kW	45.05	¢/kW/day[1]	5,656.2
Power factor correction rebate	27,292.9	kVAr	(15.32)	¢/kVAr/day[1]	(765.2)
Interruptibility rebate	38,763.1	kW	(3.83)	¢/kW/day[1]	(271.7)
Major customer connections					
Fixed charge					
Fixed (Standard connections)	408.4	Connections	150.87	¢/conn/day	225.5
Fixed (Secondary connections)	16.5	Connections	80.30	¢/conn/day	4.8
Peak charge (control period demand)	124,191.9	kVA	40.24	¢/kVA/day	18,290.8
Capacity charge					
Assessed capacity distribution	212,796.8	kVA	6.76	¢/kVA/day	5,264.9
Assessed capacity transmission	227,652.8	kVA	6.83	¢/kVA/day	5,690.8
Large capacity connections (Synlait)					
Distribution charge					
Administration	3,057.8	kVA	5.23	$/kVA/yr	16.0
Use of distribution assets	34.68	%	1,100,971	$/yr	381.8
Transmission charge					
Interconnection charge (winter)	607.3	kVA	45.21	$/kVA/yr	27.5
Interconnection charge (summer)	3,057.8	kVA	23.02	$/kVA/yr	70.4
Use of transmission connection assets	4.21	%	720,469	$/yr	30.3
Export and generation[2]					
Real power credit	3,129.8	kW	(51.88)	$/kW/yr	(162.4)
Reactive power credit	1,923.2	kVAr	(17.05)	$/kVAr/yr	(32.8)
Generation credit	357,450	kWh	(30.00)	¢/kWh	(107.2)
Miscellaneous					
Monthly invoice charge	363	Invoices/year	20.00	$/invoice	7.3
				Notional charges	196,918.6
				less Pass through costs (K_{2012})	58,846.3
				Notional Revenue (NR_{2012})	**138,072.3**

Allowable notional revenue worksheet

$$R_{2012} = ((\sum_i P_{i,2011} \; Q_{i,2010} - K_{2011}) + (R_{2011} - NR_{2011})) x ((1 + \Delta CPI_{2012}) x (1 - X))$$

($000)

	Quantities ($Q_{i,2010}$)		Previous delivery prices ($P_{i,2011}$) as at 31 March 2011		Notional annual delivery charges ($P_{i,2011}$ x $Q_{i,2010}$)
Streetlighting, general and irrigation connections					
Streetlighting fixed charge	42,015.9	Connections	10.78	¢/conn/day	1,653.2
Streetlighting and general connections					
Peak charge (peak period demand)	472,588.8	kW	42.80	¢/kW/day	73,827.8
Streetlighting, general and irrigation connections volume charge					
Working weekdays (7am - 9pm)	1,144,714.8	MWh	6.215	¢/kWh	71,144.0
Nights, weekends and holidays	1,401,838.2	MWh	0.785	¢/kWh	11,004.4
General connections					
Low power factor charge	0	kVAr	20.00	¢/kVAr/day	0.0
Irrigation connections					
Capacity charge	68,609.0	kW	44.45	¢/kW/day[1]	5,550.4
Power factor correction rebate	27,292.9	kVAr	(15.05)	¢/kVAr/day[1]	(747.6)
Interruptibility rebate	38,763.1	kW	(3.76)	¢/kW/day[1]	(265.3)
Major customer connections					
Fixed charge					
Fixed (Standard connections)	408.4	Connections	148.23	¢/conn/day	221.0
Fixed (Secondary connections)	16.5	Connections	78.89	¢/conn/day	4.8
Peak charge (control period demand)	124,191.9	kVA	39.26	¢/kVA/day	17,796.6
Capacity charge					
Assessed capacity distribution	212,796.8	kVA	6.78	¢/kVA/day	5,266.1
Assessed capacity transmission	227,652.8	kVA	6.16	¢/kVA/day	5,118.5
Large capacity connections (Synlait)					
Distribution charge					
Administration	3,057.8	kVA	5.14	$/kVA/yr	15.7
Use of distribution assets	34.68	%	1,081,717	$/yr	375.1
Transmission charge					
Interconnection charge (winter)	607.3	kVA	40.84	$/kVA/yr	24.8
Interconnection charge (summer)	3,057.8	kVA	22.79	$/kVA/yr	69.7
Use of transmission connection assets	4.21	%	745,478	$/yr	31.4
Export and generation[2]					
Real power credit	3,129.8	kW	(58.682)	$/kW/yr[3]	(183.7)
Reactive power credit	1,923.2	kVAr	(19.254)	$/kVAr/yr[3]	(37.0)
Generation credit	357,450	kWh	(30.00)	¢/kWh	(107.2)
Miscellaneous					
Monthly invoice charge	363	Invoices/year	20.00	$/invoice	7.3

Allowable notional charges	190,770.0
less Pass through costs (K_{2011})	54,792.6
plus buffer / (breach) carried forward (R_{2011} - NR_{2011})	(125.6)
	135,851.8
CPI Adjustment (ΔCPI_{2012})	1.0178
Rate of change adjustment (X)	1.0000
Allowable Notional Revenue (R_{2012})	**138,269.9**

Notes for both worksheets above:

1. The irrigation capacity charge and rebates are applied from 1 October to 31 March only.
2. Entries for export and generation represent the distribution part of payments only, the transmission part is included as an avoided transmission cost.
3. In 2011, Orion provided export to one customer under special terms that differed from our standard credit prices. The prices used in the allowable notional revenue worksheet represent the weighted average of the credit prices applied.
4. All prices and charges exclude GST.

Calculation of pass-through costs

21 Pass-through costs include transmission charges (including charges payable to Transpower and avoided transmission charges), rates payable to territorial local authorities, Electricity Authority (or Electricity Commission) levies and Commerce Act levies.

22 Transmission charges are calculated as Transpower charges (excluding the component of Transpower charges passed on transparently to electricity retailers) plus avoided transmission charges, for the two relevant periods, as follows:

Year to 31 March	**2012**	**2011**
	$000	$000
Transpower and System Operator charges		
Connection	8,914.1	9,719.7
Interconnection	45,940.3	41,191.0
New investment	464.3	485.2
Loss and constraint rebates received from Transpower	(5,605.3)	(5,015.0)
Loss and constraint rebates transparently passed on to electricity retailers	5,605.3	5,015.0
	55,318.7	51,395.9
***plus* Avoided transmission charges**		
Transmission component of amounts paid to customers with generators		
Export credits	108.7	142.9
Generation credits	126.8	92.3
Cost of transmission upgrade at Papanui grid exit	534.2	482.1
	769.7	717.3
***gives* Transmission charge**	**56,088.4**	**52,113.2**

23 Combined with rates paid to local and regional councils in respect of system fixed assets, Electricity Commission levies and Commerce Act levies, these costs represent our pass-through deduction for the periods, calculated below:

Year to 31 March	**2012**	**2011**
	$000	$000
Transmission charge (from above)	56,088.4	52,113.2
Local authority rates	1,958.8	1,825.3
Electricity Authority (or Electricity Commission) levies	486.1	388.8
Commerce Act levies	229.4	381.7
Commerce Act levies (2010) amortised	83.6	83.6
	58,846.3	**54,792.6**

Services excluded from the price path assessment

24 The determination requires us to include all prices for electricity lines services as defined in the Commerce Act 1986 (the Act). The Act specifically excludes services that are provided "mostly in competition" with another supplier.

25 As such, we have included all delivery service charges for conveying electricity in the calculation of notional revenue, except those where there is effective competition (as noted below). We also provide a range of associated services which are excluded on the basis of competition (also noted below).

26 We directly charge customers for very few services, and make extensive use of external contractors rather than maintaining contracting staff in-house. Customers requiring electrical work are generally referred to their own electrical contractor, or to a number of Orion-approved contractors for major work. Customers then pay the contractor directly. We provide other services without charge, and these are also excluded.

27 A description follows of the various types of services which Orion offers and/or provides, and the reason for their exclusion from the price path calculation.

New connections and network extensions

28 The value of assets vested in Orion by customers in the form of capital contributions is excluded. We take into account the average economic value of customer-driven network reinforcement and extensions (including new subdivisions) and, in most situations, we cover a portion of the cost of new assets. Where appropriate, we encourage the customer to select and directly employ independent contractors to design and build network extensions that comply with our published network design standard requirements and specifications.

29 In many situations there is individual consideration of the amounts that Orion contributes and the amount that the customer contributes. As such, there is often no price and no quantity, which would make it impossible to include the amounts in the assessment or compare differences from year to year.

30 Consistent with this exclusion, revenue from capital contributions is not included in our asset base or derivation of return on investment under the Commerce Commission's Input Methodologies[1].

Disconnections and reconnections

31 Disconnections and reconnections of customers' premises to our network are mostly undertaken directly by electrical contractors who are employed by the electricity retailers. Some retailer-requested disconnections and reconnections are also performed by our contractors. We then recharge the costs of undertaking the work to the retailer who requested the work. As there is effective competition for this service it has been excluded from the price path assessment.

[1] Input Methodologies (Electricity Distribution and Gas Pipeline Services) Reasons Paper dated December 2010, Appendix E, E7 (page 318)

Permanent disconnections

32 We do not charge for permanently disconnecting a property for demolition purposes, provided that adequate notice is given. Where adequate notice is not given, we either pass on the charges of an approved contractor, or charge for one of our operators at the rate that would be charged by an approved contractor (without margin).

33 Retailers have the option of employing our contractor to remove and return metering equipment at the same time the permanent disconnection is carried out. Some retailers use this service and others employ their own metering service providers. As there is effective competition for this service it has been excluded from the price path assessment.

Dedicated equipment charges to major customers

34 We charge major customers or their retailer for electricity delivery equipment that is dedicated to them. We own and maintain this equipment which includes items such as transformers, switchgear, protection devices, ripple relays and metering interface equipment. Many major customers choose to provide their own equipment or use an alternative provider. As there is effective competition for this service we have excluded it from the price path assessment.

Replacement of fuses (pole and boundary box)

35 Failed fuses are replaced by an Orion-approved contractor, or one of our operators. There is no charge to the customer for the first visit within a six month period. We charge the customer for subsequent visits at the rate billed by the contractor, without adding any margin.

Builders' temporary supplies

36 We provide a small capacity, generally single phase, unmetered builders' temporary supply service to retailers. The service includes installing and removing one of our temporary supply boxes and hire of the supply box. Electricity retailers package this with related energy and administration costs to form a retail temporary supply offering. Electricity retailers can (and do) make use of other metered and unmetered temporary supply boxes provided by other competing suppliers, and on this basis we have excluded the service from the price path assessment.

37 We do not receive revenue in respect of the provision of larger capacity three-phase temporary supplies (other than through standard delivery charges, which are included in the calculation of notional revenue).

Other services

38 Through arrangements with contractors, we organise a number of other services including high load escorts, relocation of overhead mains for bargeboard or fascia replacement, isolation for painting or tree trimming, resetting circuit breakers and switches, rewiring central supply fuses and repairs on customer premises.

39 These services are performed by a number of electrical contractors, and in most cases the customer is invoiced directly by the contractor. We have excluded these other services because they are not 'price' based and they do not form a material part of our revenue.

QUALITY STANDARD SUPPORTING INFORMATION

40 The determination sets out a quality standard that considers reliability results over a two year period and sets out requirements for the two main measures of reliability:

40.1 SAIDI, or system average interruption duration index, which reflects the average number of minutes a customer is off for each year, and

40.2 SAIFI, or system average interruption frequency index, which reflects the average number of interruptions a customer has each year.

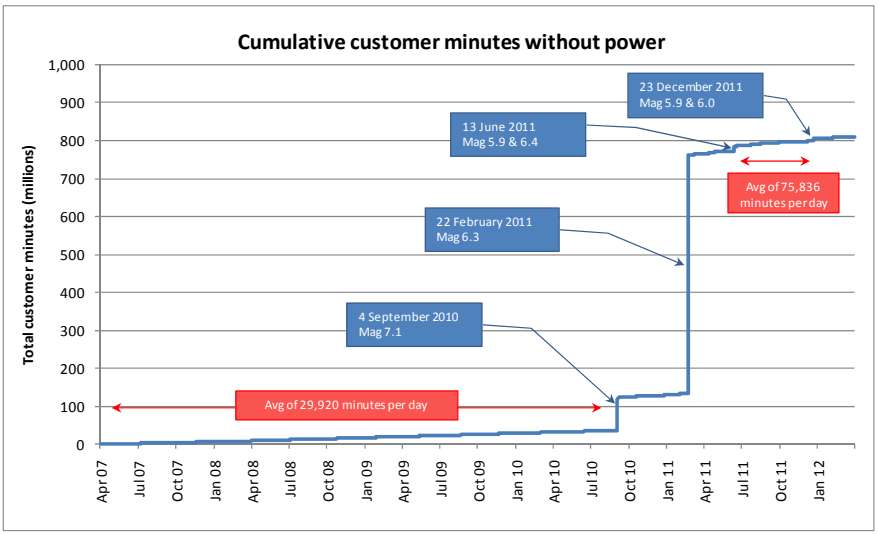
41 The Canterbury earthquakes began during the first year of the two year assessment period and have had a significant impact on our reliability results.

42 In our last annual compliance statement (dated 22 July 2011) we set out our preparedness for such an event and our response to minimise the impact. We also demonstrated that the extreme event adjustment mechanism in the determination does not adequately cater for the ongoing impact of earthquakes.

43 At a more fundamental level, we have had difficulty establishing a meaningful measure of reliability, particularly in relation to areas of the city that were deemed too dangerous to occupy, and were cordoned off. While the power remained off in these areas, there were no customers wanting supply. The point at which an outage ceases to be an outage, and becomes a normal disconnection, is not clear.

44 In relation to this, following the 22 February 2011 earthquake, we had a number of semi-permanent outages where we were unable to repair or were prevented from repairing the network, and there were no customers in the area to receive supply. To finalise numbers for the year, we manually "ended" these outages at the end of the financial year, on 31 March 2011. The outage minutes for these events are accumulated back against the day that the outages began, and the results for these particular days are capped as major event days (see below), so manually ending the outages has no impact on our final reliability position.

45 The following graph shows the accumulation of customer minutes lost over the last 5 years, depicting the normal accumulation prior to the earthquakes and the impact of the earthquakes.



46 The jumps in the results mark the immediate effect of the larger earthquakes. In addition to these jumps, the underlying rate of accumulation of minutes (between earthquakes) has altered, as indicated with the slope of the graph. Prior to the earthquakes, our long term average accumulation was just under 30,000 customer outage minutes per day. Following the earthquakes, this accumulation has more than doubled to over 75,000 customer outage minutes per day.

47 In relation to this, regardless of the future incidence of earthquakes, we observe that our underlying reliability has materially altered, and consider that it is no longer appropriate to compare reliability results with those achieved prior to the earthquakes. A number of factors have affected this underlying reliability, including:

47.1 Many assets, particularly underground cables, have been damaged during earthquakes but do not fail until sometime later. Often this delayed failure will occur when seasonal changes lead to wetter conditions and moisture enters damaged insulation, or as the network becomes more heavily loaded during winter. It would be cost-prohibitive to replace cables on a precautionary basis, and it is not always possible to establish if earthquakes were the original cause of any specific failure.

47.2 Some areas of our network are operating with a lower level of security than we would normally provide. This occurs where our backup supply systems are damaged, or where our primary supply systems have been damaged and we are relying on backup systems. In these situations, outages last until we can fix a fault, rather than being able to restore supply via alternative routes while repair work is carried out.

47.3 Increased civil works in relation to repair work for other services (roading, water, waste water and telecommunications) has led to a higher incidence of third-party damage to our assets.

47.4 We have installed a number of temporary over-head high-voltage feeders to restore supply in our eastern suburbs. A normal attribute of overhead lines is that they provide a lower level of reliability than underground cables. We have observed a number of outages that have affected large areas of the city as a result of faults (such as bird strike) on these lines.

47.5 There is an increasing number of requests for planned outages as the demolition work in the city continues, and as we begin to enter a long re-building phase. Much of this work requires alterations to our network which result in planned (notified) outages.

48 As a result, we consider that our reliability has fundamentally changed, and the method taken in the determination of measuring and assessing reliability against historical results is no longer appropriate.

49 The following section describes our policies and procedures for recording outage information, and this is followed by the derivation of our reliability limits and a representation of our reliability results for the year to 31 March 2011, and for the year to 31 March 2012.

Recording reliability information

50 Orion has been developing its network management system over recent years and in November 2011 we commissioned an outage management system to operate under our new "PowerOn" SCADA network management system. Significantly, the new system maintains a live model of our high voltage network which includes information on customer connection points.

51 For planned outages and following network faults, our network controllers follow sequential operating orders to carry out switching and configuration changes on the network to bypass affected assets and facilitate planned or remedial work. At each point during these operating orders PowerOn determines and records the number of connections affected, together with switching points and switching times.

52 Prior to using this system, as described in previous compliance statements, our hard-copy operating orders were manually interrogated to determine the number of connections affected. This required us to run a trace on our separate GIS mapping system to determine the number of customers affected, with adjustments where the GIS configuration did not match the network configuration during outages.

53 We are further developing our PowerOn system to collate a record of outage results over time, and this will further enhance our capabilities in future. Currently, we are maintaining our control centre reliability log where the results of the operating orders are manually recorded, including:

53.1 district substation;

53.2 feeder;

53.3 switching device where isolation occurred;

53.4 asset type affected;

53.5 cause of interruption;

53.6 time/date off;

53.7 time/date for each restored section;

53.8 number of consumers affected in each restored section; and

53.9 explanatory notes.

54 The 22 February 2011 earthquake occurred before we commissioned the outage management part of our PowerOn system, and the magnitude of the damage and degree of network reconfiguration required us to take a different approach to outage recording for this event. Significant network reconfiguration was required to by-pass damaged assets and progressively restore supply in the hours and days following the earthquake, and we also installed generators in a number of situations.

55 With ongoing configuration changes, it was not possible to use a network-trace in the largely static GIS network model to establish the number of customers affected. Instead, our control centre engineers assessed the number of connections affected based on loading levels and knowledge of the network (rather than using the GIS network trace). With the large number of connections affected, we consider that this temporary alternative approach provided a materially correct representation of the interruptions.

56 In all cases, the control centre reliability log information is then loaded in a reliability database, and reliability statistics are queried from this database as required.

57 To establish our system average reporting measures, the total number of connected consumers on the network is obtained from our connections database. We maintain details of all our network connections on this database, and we regularly undertake reconciliations with the Electricity Authority Registry.

Reliability Limits

58 Using our Reliability database we extracted daily records on the sum of customer minutes and sum of customers affected during Class B (planned) interruptions and Class C (unplanned) interruptions on our network over the reference period (1 April 2004 to 31 March 2009). We then excluded days with no outages to develop a non-zero dataset. Using the above data and based on the total number of customers used in the derivation of annual reliability statistics we calculated daily SAIDI and SAIFI.

59 The SAIDI and SAIFI results are assumed to follow a lognormal distribution and the determination establishes boundary values 2.5 standard deviations from the average. Any days where the SAIDI result exceeds this boundary value is classified as a major event day and the SAIDI and SAIFI results for that day are "normalised" by reducing them to their respective boundary values.

60 The SAIDI boundary value is described by the expression:

$$B_{SAIDI} = e^{(\alpha_{SAIDI} + 2.5\,\beta_{SAIDI})}$$

where α_{SAIDI} is the average of the natural logarithm of each daily SAIDI value, which we have calculated as -2.843 , and

β_{SAIDI} is the standard deviation of the natural logarithm of each daily SAIDI value, which we have calculated as 1.777.

Substituting the average and standard deviation gives:

$$B_{SAIDI} = e^{(-2.843+2.5\times1.777)}$$
$$= 4.95$$

61 The SAIFI boundary value is described by the expression:

$$B_{SAIFI} = e^{(\alpha_{SAIFI} + 2.5\,\beta_{SAIFI})}$$

where α_{SAIFI} is the average of the natural logarithm of each daily SAIFI value, which we have calculated as -7.574, and

β_{SAIFI} is the standard deviation of the natural logarithm of each daily SAIFI value, which we have calculated as 1.996

Substituting the average and standard deviation gives:

$$B_{SAIFI} = e^{(-7.574+2.5\times1.996)}$$
$$= 0.075$$

62 The dataset is then normalised by replacing any daily SAIDI result that is greater than the SAIDI boundary value with the SAIDI boundary value, and on these same days, reducing the SAIFI value to the SAIFI boundary value (if it is greater). This resulted in two changes to the dataset, as follows:

62.1 19 September 2005: SAIDI result of 12.20 reduced to 4.95, SAIFI result of 0.048 remains unchanged, and

62.2 12 June 2006: SAIDI result of 100.29 reduced to 4.95, SAIFI result of 0.074 remains unchanged.

63 Both these events relate to snowstorms.

64 Our reliability limits are then established as the point one standard deviation above the average for the normalised dataset.

65 The SAIDI limit is described by the expression:

$$SAIDI_{LIMIT} = \mu_{SAIDI} + \sigma_{SAIDI}$$

where μ_{SAIDI} is the annual average SAIDI in the normalised dataset, which we have calculated as 52.99, and

σ_{SAIDI} is the standard deviation of SAIDI in the normalised dataset which is annualised by multiplying it by the square root of the number of days in the year, which we have calculated as 6.74

Substituting the average and standard deviation gives:

$$SAIDI_{LIMIT} = 52.99 + 6.74$$

$$= 59.73$$

66 The SAIFI limit is described by the expression:

$$SAIFI_{LIMIT} = \mu_{SAIFI} + \sigma_{SAIFI}$$

where μ_{SAIFI} is the annual average SAIFI in the normalised dataset, which we have calculated as 0.676, and

σ_{SAIFI} is the standard deviation of SAIFI in the normalised dataset which is annualised by multiplying it by the square root of the number of days in the year, which we have calculated as 0.100

Substituting the average and standard deviation gives:

$$SAIFI_{LIMIT} = 0.676 + 0.100$$

$$= 0.776$$

67 Therefore, based on the 5 years from 1 April 2005 to 31 March 2009, our SAIDI limit is 59.73 and SAIFI limit is 0.776. These limits will remain in place until 31 March 2015.

Assessed Values

68 This section describes our reliability results for the year to 31 March 2011 and the year to 31 March 2012 in comparison with the relevant limit determined above.

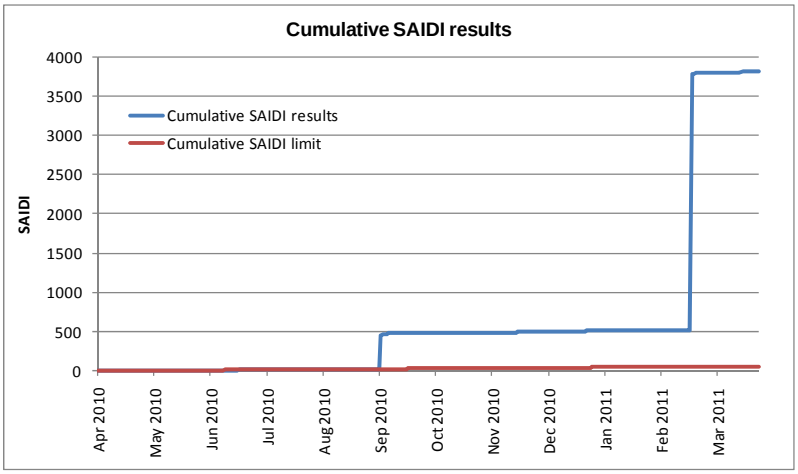
Actual reliability results

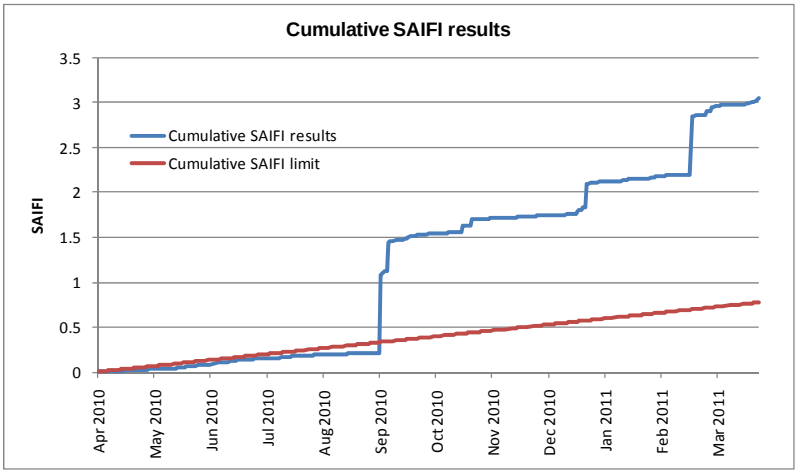
69 Our actual reliability results (prior to normalising the data for extreme events) were:

	Limit	Year to 31 March 2011	Year to 31 March 2012
SAIDI	59.73	3,811.60	230.56
SAIFI	0.776	3.044	2.218

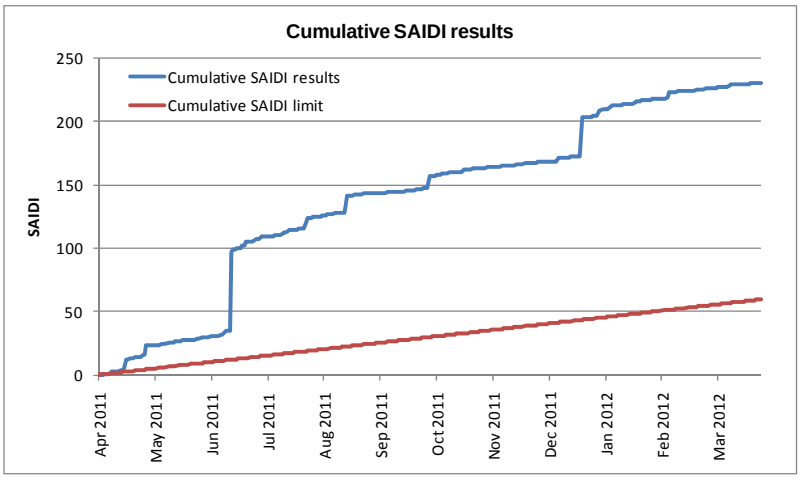
70 Graphing the cumulative SAIDI and SAIFI throughout the assessment periods shows that we remained within our limits until the earthquakes began on 4 September 2010, and shows the significant impact of the earthquakes:

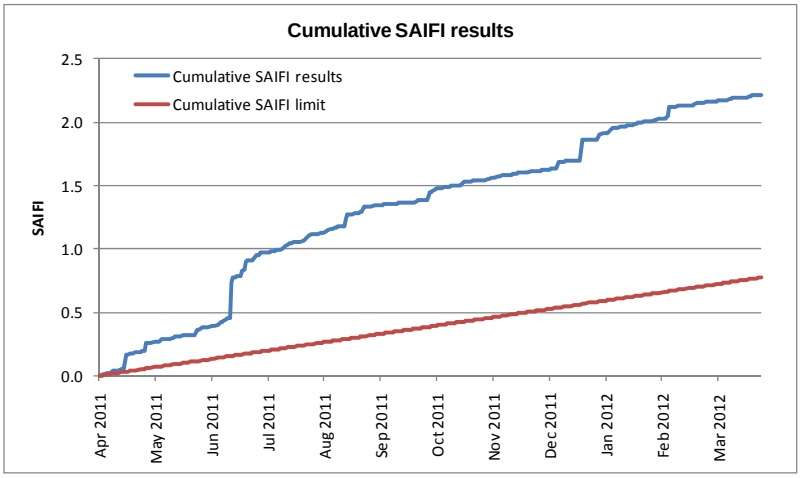
Year to 31 March 2011





Year to 31 March 2012





71 For both SAIDI and SAIFI, for both years, our raw results exceeded our reliability limits.

Normalising the reliability results

72 The determination provides for the normalisation of results to mitigate the impact of extreme events and provide a view of underlying reliability results. In the assessment dataset we identified 15 days that met the definition of a major event day (MED) as the daily SAIDI exceeded the boundary value of 4.95.

73 The assessment dataset is normalised by adjusting the results on major event days, replacing the daily SAIDI with the SAIDI boundary value of 4.95 and reducing the daily SAIFI to the SAIFI boundary value of 0.075 (if it is greater). The changes are:

Major event day adjustments

Date	Daily SAIDI adjustment	Daily SAIFI adjustment	Cause
4 September 2010	432.47 reduced to 4.95	0.861 reduced to 0.075	7.1 magnitude earthquake centred near Darfield
5 September 2010	12.59 reduced to 4.95	0.029 unchanged	Total of 232 aftershocks with 5 quakes in excess of magnitude 4.5
8 September 2010	12.99 reduced to 4.95	0.323 reduced to 0.075	Total of 138 aftershocks with 3 quakes in excess of magnitude 4.5
21 December 2010	5.14 reduced to 4.95	0.028 unchanged	Wind storm affecting rural parts of our network, with norwest winds gusting in excess of 100km/h
26 December 2010	8.63 reduced to 4.95	0.271 reduced to 0.075	“Boxing Day” earthquake, magnitude 4.9 close to Christchurch CBD
22 February 2011	3260.51 reduced to 4.95	0.650 reduced to 0.075	Devastating 6.3 magnitude earthquake centred under the Port Hills with significant energy release directed at Christchurch CBD.
9 March 2011	7.60 reduced to 4.95	0.009 unchanged	Delayed faults from 22 February 2011 earthquake affecting less than 50 customers in an area that remained cordoned off for an extended period of time.
16 April 2011	8.94 reduced to 4.95	0.111 reduced to 0.075	5.3 magnitude earthquake caused a fault in our 66kV supply to a high density urban area for several hours.
27 April 2011	6.91 reduced to 4.95	0.064 unchanged	Delayed fault to a communications cable led to loss of supply from one of our significant urban substations for a number of hours.
13 June 2011	61.68 reduced to 4.95	0.275 reduced to 0.075	Magnitude 5.9 and 6.4 earthquakes centred under Port Hills, close to Sumner.
24 July 2011	5.67 reduced to 4.95	0.018 unchanged	Snowstorm, reported as “The worst snow fall in 15 years blanketed quake-hit Christchurch overnight with up to 30cm of snow covering the city”
15 August 2011	6.16 reduced to 4.95	0.048 unchanged	Snowstorm, reported as “New Zealand's biggest snow storm in 50 years”. In Christchurch there was a little less snow than the snowstorm 3 weeks prior, but the snow was wetter, heavier and the poor weather conditions lasted longer.
16 August 2011	6.39 reduced to 4.95	0.037 unchanged	
30 September 2011	9.49 reduced to 4.95	0.061 unchanged	Fault on temporary 66kV overhead line feeding Christchurch eastern suburbs for several hours. Suspected bird strike.
23 December 2011	31.22 reduced to 4.95	0.159 reduced to 0.075	Magnitude 5.9 and 6.0 earthquakes centred near the coast close to Christchurch eastern suburbs.

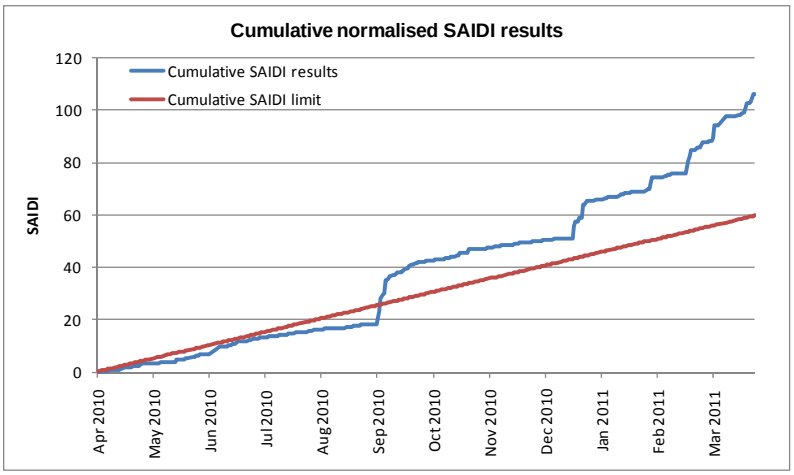
74 We note that, in both years, while operating to an annual SAIDI limit of 59.73, the requirement to add 4.95 on major event days is still a significant addition, and uses up more than half our allowable SAIDI minutes on the extreme days alone. Our normalised results exceed our reliability limits and the corresponding graphs of our normalised results show that the extreme event adjustment does not adequately exclude the impact of extreme events, and does not achieve the purpose of providing a basis of assessment of underlying reliability.

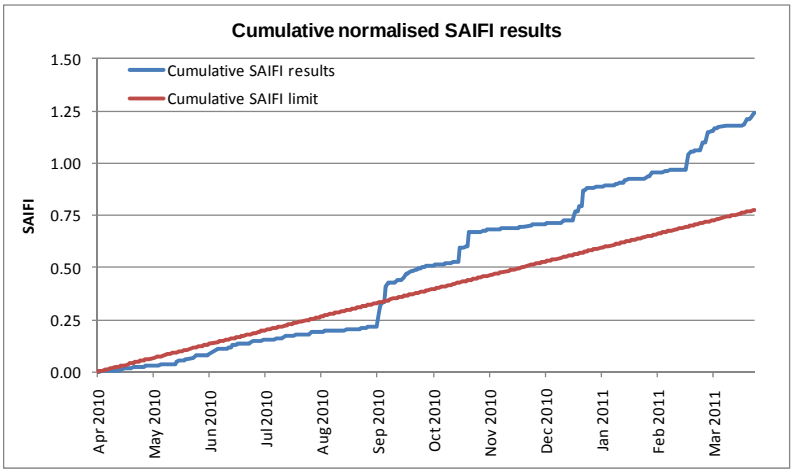
75 Our normalised reliability results were:

	Limit	Year to 31 March 2011	Year to 31 March 2012
SAIDI	59.73	106.34	133.72
SAIFI	0.776	1.239	1.897

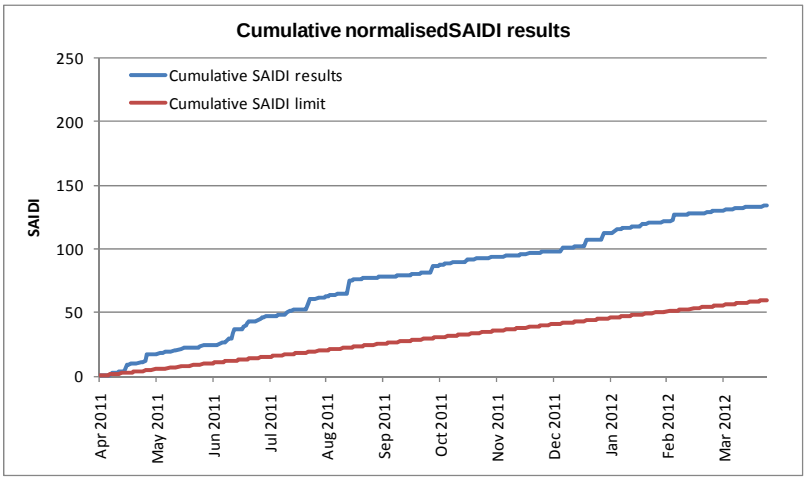
76 The corresponding graph of our normalised results shows the progression of our reliability results through the two assessment periods:

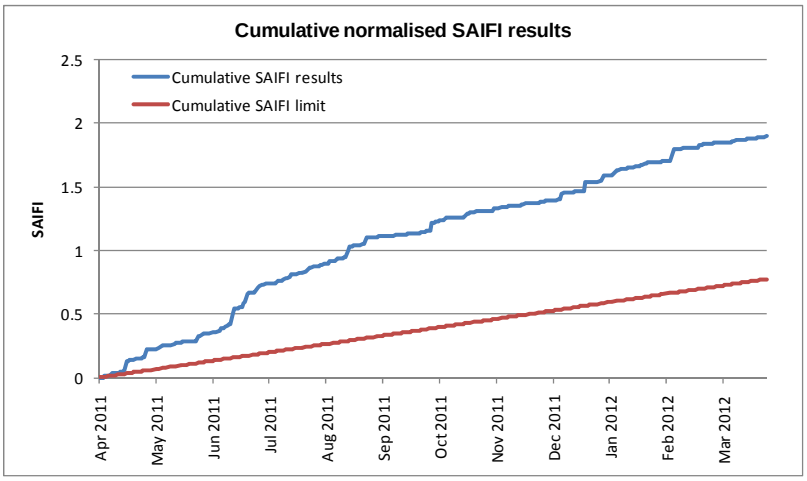
Year to 31 March 2011





Year to 31 March 2012





77 Clause 9.1 of the determination requires that we either:

77.1 comply with the reliability requirement for the assessment period (the year to 31 March 2012), or

77.2 have complied with the reliability requirement in the preceding two assessment periods (in this case, there is only one preceding assessment period, being the year to 31 March 2011).

78 The determination sets out the reliability requirement as:

$$\frac{SAIDI_{ASSESS,t}}{SAIDI_{LIMIT}} \leq 1$$

$$\frac{SAIFI_{ASSESS,t}}{SAIFI_{LIMIT}} \leq 1$$

79 As our assessed SAIDI and SAIFI results for both years exceed the respective limits, we do not comply with either of the reliability requirements set out in the determination.

APPENDIX A – DELIVERY AND EXPORT PRICE SCHEDULES

Delivery prices

(applicable from 1 April 2011 to 31 March 2012)

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)	All prices exclude GST
Streetlighting connections			*approx 42,400 connections*	
Fixed charge	11.05	-	11.05	¢/conn/day
Peak charge (peak period demand)	30.66	12.31	42.97	¢/kW/day
Volume charge				
Working weekdays (7am - 9pm)	4.886	1.660	6.546	¢/kWh
Nights, weekends and holidays	0.579	0.251	0.830	¢/kWh
General connections			*approx 191,100 connections*	
Peak charge (peak period demand)	30.66	12.31	42.97	¢/kW/day
Volume charge				
Working weekdays (7am - 9pm)	4.886	1.660	6.546	¢/kWh
Nights, weekends and holidays	0.579	0.251	0.830	¢/kWh
Low power factor charge	15.00	5.00	20.00	¢/kVAr/day
Irrigation connections			*approx 1,160 connections*	
Capacity charge	43.90	1.15	45.05	¢/kW/day*
Volume charge				
Working weekdays (7am - 9pm)	4.886	1.660	6.546	¢/kWh
Nights, weekends and holidays	0.579	0.251	0.830	¢/kWh
Rebates				
Power factor correction rebate	(15.32)	-	(15.32)	¢/kVAr/day*
Interruptibility rebate	(3.83)	-	(3.83)	¢/kW/day*
	* applied from 1 October to 31 March only			
Major customer and embedded network connections			*approx 480 connections*	
Fixed charge				
Fixed (standard connections)	150.87	-	150.87	¢/conn/day
Fixed (secondary connections)	80.30	-	80.30	¢/conn/day
Dedicated equipment	see separate price schedule			
Peak charge (control period demand)	27.07	13.17	40.24	¢/kVA/day
Capacity charge				
Assessed capacity distribution	6.76	-	6.76	¢/kVA/day
Assessed capacity transmission	-	6.83	6.83	¢/kVA/day
Large capacity connections			*2 connections*	
Distribution and transmission charges	*individually assessed*			
Miscellaneous				
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 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 connection.

Delivery prices

(applicable from 1 April 2010 to 31 March 2011)

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)	All prices exclude GST
Streetlighting connections			*approx 42,100 connections*	
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
General connections			*approx 189,400 connections*	
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
Irrigation connections			*approx 1,160 connections*	
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			
Major customer and embedded network connections			*approx 470 connections*	
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
Large capacity connections				*2 connections*
Distribution and transmission charges	*individually assessed*			
Miscellaneous				
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 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 connection.

Export and generation credits

(applicable from 1 April 2011 to 31 March 2012)

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	All prices exclude GST
0 - 30kW Anytime credits[2]	Anytime (24 hours, 7 days)	0.593	0.407	1.000	¢/kWh
- or -					
0 - 30kW Peak period credits[2]	General connection chargeable peak period	41.50	28.50	70.00	¢/kWh
30 - 750kW Control period credits	Major customer control period				
- real power		51.88	35.64	87.52	$/avg kW/yr
- reactive power		17.05	0.00	17.05	$/avg kVAr/yr
above 750 kW	*Individually assessed prices provided on application*				

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 22 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 100kW.

Generator output	Period applied	Distribution	Transmission	Delivery	All prices exclude GST
100 - 750kW Generation period	Orion's ripple signalled generation period	30.0	30.0	60.00	¢/kWh
Above 750 kW	*Individually assessed prices provided on application*				

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 38 connections are approved for generation credits.

Export and generation credits

(applicable from 1 April 2010 to 31 March 2011)

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	All prices exclude GST
0 - 30kW Anytime credits[2]	Anytime (24 hours, 7 days)	0.657	0.410	1.067	¢/kWh
- or -					
0 - 30kW Peak period credits[2]	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	*Individually assessed prices provided on application*				

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	All prices exclude GST
30 - 750kW Generation period	Orion's ripple signalled generation period	30.0	30.0	60.00	¢/kWh
Above 750 kW	*Individually assessed prices provided on application*				

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.

DIRECTORS' CERTIFICATE
ON ANNUAL COMPLIANCE STATEMENT

We, Craig David Boyce and John Allen Dobson, being directors of Orion New Zealand Ltd, certify that, having made all reasonable enquiry, to the best of our knowledge and belief, the attached Annual Compliance Statement of Orion New Zealand Limited, and related information, prepared for the purposes of the Electricity Distribution Services Default Price-Quality Path Determination 2010 are true and accurate.

Craig David Boyce

John Allen Dobson

Dated 6 June 2012

AUDIT NEW ZEALAND
Mana Arotake Aotearoa

Independent Auditor's Report

To the directors of Orion New Zealand Limited

The Auditor General is the auditor of Orion New Zealand Limited (the company). The Auditor General has appointed me, Scott Tobin, using the staff and resources of Audit New Zealand, to provide an opinion, on her behalf, on the company's Annual Compliance Statement for the assessment period ended on 31 March 2012 on pages 3 to 29 regarding compliance with the Electricity Distribution Services Default Price-Quality Path Determination 2010.

We have audited the Annual Compliance Statement in respect of the default price-quality path prepared by the company for the assessment period ended on 31 March 2012 and dated 6 June 2012 for the purposes of clause 11 of the Electricity Distribution Services Default Price-Quality Path Determination 2010 (the Determination).

Directors' Responsibilities

The Directors of the company are responsible for the preparation of the Annual Compliance Statement in accordance with the Determination and for such internal control as the Directors determine is necessary to enable the preparation of an Annual Compliance Statement that is free from material misstatement, whether due to fraud or error.

Auditor's Responsibilities

Our responsibility is to express an opinion on the Annual Compliance Statement based on our audit. We conducted our audit in accordance with the External Reporting Board Standard on Assurance Engagements 3100: Compliance Engagements. This standard requires that we comply with ethical and quality control requirements and plan and perform the audit to obtain reasonable assurance about whether the Annual Compliance Statement has been prepared in accordance with the Determination and is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Annual Compliance Statement. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the Annual Compliance Statement, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation of the Annual Compliance Statement in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control.

In relation to the price path set out in clause 8 of the Determination, our audit included examination, on a test basis, of evidence relevant to the amounts and disclosures contained on pages 4 to 16 and 25 to 28 of the Annual Compliance Statement.

In relation to the SAIDI and SAIFI statistics for the Reference Period and the Assessment Period ended on 31 March 2012, including the calculation of the Reliability Limits and the Assessed Values, which are relevant to the quality standards set out in clause 9 of the Determination, our audit included examination, on a test basis, of evidence relevant to the amounts and disclosures contained on pages 17 to 23 of the Annual Compliance Statement.

Our audit also included assessment of the significant estimates and judgements, if any, made by the company in the preparation of the Annual Compliance Statement.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Limitations and Use of this Independent Auditor's Report

This independent auditor's report has been prepared solely for the Directors of the company and the Commerce Commission in accordance with the Determination. We disclaim any assumption of responsibility for any reliance on this report to any persons or users other than the Directors of the company and the Commerce Commission, or for any purpose other than that for which it was prepared.

Because of the inherent limitations in evidence gathering procedures, it is possible that fraud, error or non-compliance may occur and not be detected. As the procedures performed for this engagement are not performed continuously throughout the assessment period and the procedures performed in respect of the company's compliance with the Determination are undertaken on a test basis, our engagement cannot be relied on to detect all instances where the company may not have complied with the Determination. Our opinion has been formed on the above basis.

Independence

In addition to this audit, we issued an audit opinion on the company and group's financial statements under the Energy Companies Act 1992 for the financial year ended 31 March 2012. This audit engagement is compatible with the independence requirements in the Determination.

Other than this audit and the audit of the financial statements, we have no relationship with or interests in the company or any of its subsidiaries.

Opinion

In our opinion, the Annual Compliance Statement of the company for the Assessment Period ended on 31 March 2012, has been prepared, in all material respects, in accordance with the Determination.

Our audit was completed on 6 June 2012 and our opinion is expressed as at that date.

Scott Tobin
Audit New Zealand
On behalf of the Auditor-General
Christchurch, New Zealand

Matters relating to the electronic publication of the annual compliance statement prepared under the Commerce Act (Electricity Distribution Default Price Quality Path) Determination 2010

This audit report relates to the electronic publication of the annual compliance statement prepared under the Commerce Act (Electricity Distribution Default Price Quality Path) Determination 2010 (the "annual compliance statement") of the company for the assessment period ended on 31 March 2012.

We have not been engaged to report on the integrity of any website on which the annual compliance statement has been published. We accept no responsibility for any changes that may have occurred to the annual compliance statement since it was initially approved and published.

This audit report refers only to the annual compliance statement named above. If readers of this audit report are concerned with the inherent risks arising from electronic data communication they should refer to the original published hard copy of the annual compliance statement and related audit report dated 6 June 2012 to confirm the information included in the annual compliance statement published on this website.

Legislation in New Zealand governing the preparation and dissemination of financial information may differ from legislation in other jurisdictions.