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# Information Disclosure

For the year ended 31 March 2015

*Pursuant to the Electricity Distribution Information Disclosure Determination 2012*

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Company Name **Aurora Energy Limited**  
For Year Ended **31 March 2015**

## SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with the ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of the determination.

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

### 1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs (\$/GWh)	Expenditure per average no. of ICPs (\$/ICP)	Expenditure per MW maximum coincident system demand (\$/MW)	Expenditure per km circuit length (\$/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers (\$/MVA)
<b>Operational expenditure</b>	18,915	278	82,603	4,060	27,647
Network	9,899	145	43,229	2,125	14,469
Non-network	9,016	132	39,374	1,935	13,178
<b>Expenditure on assets</b>	23,364	343	102,036	5,015	34,151
Network	23,364	343	102,036	5,015	34,151
Non-network	–	–	–	–	–

### 1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs (\$/GWh)	Revenue per average no. of ICPs (\$/ICP)
<b>Total consumer line charge revenue</b>	71,574	1,051
Standard consumer line charge revenue	71,696	1,048
Non-standard consumer line charge revenue	46,588	31,419

### 1(iii): Service intensity measures

Demand density	49	Maximum coincident system demand per km of circuit length (for supply) (kW/km)
Volume density	215	Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)
Connection point density	15	Average number of ICPs per km of circuit length (for supply) (ICPs/km)
Energy intensity	14,683	Total energy delivered to ICPs per average number of ICPs (kWh/ICP)

### 1(iv): Composition of regulatory income

	(\$000)	% of revenue
Operational expenditure	23,608	25.26%
Pass-through and recoverable costs excluding financial incentives and wash-ups	34,483	36.89%
Total depreciation	11,941	12.78%
Total revaluations	273	0.29%
Regulatory tax allowance	5,781	6.19%
Regulatory profit/(loss) including financial incentives and wash-ups	17,923	19.18%
<b>Total regulatory income</b>	<b>93,463</b>	

### 1(v): Reliability

Interruption rate	13.84	Interruptions per 100 circuit km
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Company Name **Aurora Energy Limited**  
For Year Ended **31 March 2015**

## SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).

EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).

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sch ref

### 2(i): Return on Investment

#### ROI – comparable to a post tax WACC

Reflecting all revenue earned  
Excluding revenue earned from financial incentives  
Excluding revenue earned from financial incentives and wash-ups

CY-2 31 Mar 13 %	CY-1 31 Mar 14 %	Current Year CY 31 Mar 15 %
6.56%	5.95%	4.72%
6.56%	5.95%	4.72%
6.56%	5.95%	4.72%

#### Mid-point estimate of post tax WACC

25th percentile estimate  
75th percentile estimate

5.85%	5.43%	6.10%
5.13%	4.71%	5.39%
6.56%	6.14%	6.82%

#### ROI – comparable to a vanilla WACC

Reflecting all revenue earned  
Excluding revenue earned from financial incentives  
Excluding revenue earned from financial incentives and wash-ups

7.34%	6.64%	5.50%
7.34%	6.64%	5.50%
7.34%	6.64%	5.50%

#### WACC rate used to set regulatory price path

8.77%	8.77%	8.77%
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#### Mid-point estimate of vanilla WACC

25th percentile estimate  
75th percentile estimate

6.62%	6.11%	6.89%
5.91%	5.39%	6.17%
7.34%	6.83%	7.60%

### 2(ii): Information Supporting the ROI

(\$000)

Total opening RAB value  
plus Opening deferred tax

324,967	
(1,920)	
	323,047

#### Opening RIV

#### Line charge revenue

90,830

Expenses cash outflow  
add Assets commissioned  
less Asset disposals  
add Tax payments  
less Other regulated income

58,091
17,298
–
6,110
2,633

#### Mid-year net cash outflows

78,866

#### Term credit spread differential allowance

–

Total closing RAB value  
less Adjustment resulting from asset allocation  
less Lost and found assets adjustment  
plus Closing deferred tax

330,597
0
–
(1,592)

#### Closing RIV

329,005

#### ROI – comparable to a vanilla WACC

5.50%

Leverage (%)  
Cost of debt assumption (%)  
Corporate tax rate (%)

44%  
6.36%  
28%

#### ROI – comparable to a post tax WACC

4.72%

Company Name

Aurora Energy Limited

For Year Ended

31 March 2015

**SCHEDULE 2: REPORT ON RETURN ON INVESTMENT**

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EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).

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sch ref

**2(iii): Information Supporting the Monthly ROI**

Opening RIV

N/A

	Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
April						–
May						–
June						–
July						–
August						–
September						–
October						–
November						–
December						–
January						–
February						–
March						–
<b>Total</b>	–	–	–	–	–	–

Tax payments

N/A

Term credit spread differential allowance

N/A

Closing RIV

N/A

Monthly ROI – comparable to a vanilla WACC

N/A

Monthly ROI – comparable to a post tax WACC

N/A

**2(iv): Year-End ROI Rates for Comparison Purposes**

Year-end ROI – comparable to a vanilla WACC

5.40%

Year-end ROI – comparable to a post tax WACC

4.62%

\* these year-end ROI values are comparable to the ROI reported in pre 2012 disclosures by EDBs and do not represent the Commission's current view on ROI.

**2(v): Financial Incentives and Wash-Ups**

Net recoverable costs allowed under incremental rolling incentive scheme

–

Purchased assets – avoided transmission charge

–

Energy efficiency and demand incentive allowance

–

Quality incentive adjustment

–

Other financial incentives

–

**Financial incentives**

–

**Impact of financial incentives on ROI**

–

Input methodology claw-back

–

Recoverable customised price-quality path costs

–

Catastrophic event allowance

–

Capex wash-up adjustment

–

Transmission asset wash-up adjustment

–

2013–2015 NPV wash-up allowance

–

Reconsideration event allowance

–

Other wash-ups

–

**Wash-up costs**

–

**Impact of wash-up costs on ROI**

–

Company Name **Aurora Energy Limited**  
For Year Ended **31 March 2015**

### SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

#### 3(i): Regulatory Profit

(\$000)

##### Income

Line charge revenue

90,830

plus Gains / (losses) on asset disposals

–

plus Other regulated income (other than gains / (losses) on asset disposals)

2,633

##### Total regulatory income

93,463

##### Expenses

less Operational expenditure

23,608

less Pass-through and recoverable costs excluding financial incentives and wash-ups

34,483

##### Operating surplus / (deficit)

35,372

less Total depreciation

11,941

plus Total revaluations

273

##### Regulatory profit / (loss) before tax

23,704

less Term credit spread differential allowance

–

less Regulatory tax allowance

5,781

##### Regulatory profit/(loss) including financial incentives and wash-ups

17,923

#### 3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups

(\$000)

##### Pass through costs

Rates

979

Commerce Act levies

166

Industry levies

324

CPP specified pass through costs

–

##### Recoverable costs excluding financial incentives and wash-ups

Electricity lines service charge payable to Transpower

25,562

Transpower new investment contract charges

–

System operator services

–

Distributed generation allowance

6,656

Extended reserves allowance

–

Other recoverable costs excluding financial incentives and wash-ups

796

##### Pass-through and recoverable costs excluding financial incentives and wash-ups

34,483

Company Name **Aurora Energy Limited**  
 For Year Ended **31 March 2015**

### SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).

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sch ref

#### 3(iii): Incremental Rolling Incentive Scheme

(\$000)

CY-1 CY  
 31 Mar 14 31 Mar 15

Allowed controllable opex

Actual controllable opex

Incremental change in year

Previous years' incremental change Previous years' incremental change adjusted for inflation

CY-5 31 Mar 10

CY-4 31 Mar 11

CY-3 31 Mar 12

CY-2 31 Mar 13

CY-1 31 Mar 14

Net incremental rolling incentive scheme

Net recoverable costs allowed under incremental rolling incentive scheme

#### 3(iv): Merger and Acquisition Expenditure

(\$000)

Merger and acquisition expenditure

Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)

#### 3(v): Other Disclosures

(\$000)

Self-insurance allowance

Company Name **Aurora Energy Limited**  
 For Year Ended **31 March 2015**

#### SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.

EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

sch ref	4(i): Regulatory Asset Base Value (Rolled Forward)	for year ended	RAB	RAB	RAB	RAB	RAB
			31 Mar 11 (\$000)	31 Mar 12 (\$000)	31 Mar 13 (\$000)	31 Mar 14 (\$000)	31 Mar 15 (\$000)
7							
8							
9							
10	Total opening RAB value		294,631	307,618	313,820	318,316	324,967
11							
12	less Total depreciation		10,301	10,796	11,086	11,473	11,941
13							
14	plus Total revaluations		7,125	4,832	2,696	4,879	273
15							
16	plus Assets commissioned		16,369	12,735	12,886	13,374	17,298
17							
18	less Asset disposals		206	569		129	—
19							
20	plus Lost and found assets adjustment						—
21							
22	plus Adjustment resulting from asset allocation						0
23							
24	Total closing RAB value		307,618	313,820	318,316	324,967	330,597
25							

#### 4(ii): Unallocated Regulatory Asset Base

sch ref		Unallocated RAB *		RAB	
		(\$000)	(\$000)	(\$000)	(\$000)
26					
27					
28					
29	Total opening RAB value		324,967		324,967
30	less				
31	Total depreciation		11,941		11,941
32	plus				
33	Total revaluations		273		273
34	plus				
35	Assets commissioned (other than below)	4,103		4,103	
36	Assets acquired from a regulated supplier	—		—	
37	Assets acquired from a related party	13,195		13,195	
38	Assets commissioned		17,298		17,298
39	less				
40	Asset disposals (other than below)	—		—	
41	Asset disposals to a regulated supplier	—		—	
42	Asset disposals to a related party	—		—	
43	Asset disposals		—		—
44					
45	plus Lost and found assets adjustment		—		—
46					
47	plus Adjustment resulting from asset allocation				0
48					
49	Total closing RAB value		330,597		330,597

\* The 'unallocated RAB' is the total value of those assets used wholly or partially to provide electricity distribution services without any allowance being made for the allocation of costs to services provided by the supplier that are not electricity distribution services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.



Company Name **Aurora Energy Limited**  
 For Year Ended **31 March 2015**

#### SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.

EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

51

52

#### 4(iii): Calculation of Revaluation Rate and Revaluation of Assets

53

54

CPI<sub>t</sub>

1,193

55

CPI<sub>t</sub><sup>4</sup>

1,192

56

Revaluation rate (%)

0.08%

57

58

59

60

Total opening RAB value

Unallocated RAB *		RAB	
(\$000)	(\$000)	(\$000)	(\$000)
324,967		324,967	
—		—	
324,967		324,967	
	273		273

61

less Opening value of fully depreciated, disposed and lost assets

62

63

Total opening RAB value subject to revaluation

64

Total revaluations

65

66

#### 4(iv): Roll Forward of Works Under Construction

67

68

Works under construction—preceding disclosure year

Unallocated works under construction		Allocated works under construction	
	8,062		8,062
24,728		24,728	
17,298		17,298	
	15,492		15,492

69

plus Capital expenditure

70

less Assets commissioned

71

plus Adjustment resulting from asset allocation

72

Works under construction - current disclosure year

73

74

Highest rate of capitalised finance applied

75

Company Name **Aurora Energy Limited**  
 For Year Ended **31 March 2015**

#### SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.

EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

#### 4(v): Regulatory Depreciation

Depreciation - standard  
 Depreciation - no standard life assets  
 Depreciation - modified life assets  
 Depreciation - alternative depreciation in accordance with CPP  
**Total depreciation**

Unallocated RAB *	RAB	
(\$000)	(\$000)	(\$000)
11,941	11,941	
	11,941	11,941

#### 4(vi): Disclosure of Changes to Depreciation Profiles

(\$000 unless otherwise specified)

Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation

\* include additional rows if needed

#### 4(vii): Disclosure by Asset Category

(\$000 unless otherwise specified)

	Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
<b>Total opening RAB value</b>	13,569	9,460	54,694	46,641	125,524	51,047	19,999	4,033	—	324,967
less Total depreciation	549	373	2,101	2,233	3,796	1,705	983	201		11,941
plus Total revaluations	11	8	46	39	106	43	17	3		273
plus Assets commissioned	626	—	6,369	4,827	3,058	1,816	556	46		17,298
less Asset disposals										—
plus Lost and found assets adjustment										—
plus Adjustment resulting from asset allocation										—
plus Asset category transfers										—
<b>Total closing RAB value</b>	13,657	9,095	59,008	49,274	124,892	51,201	19,589	3,881	—	330,597
<b>Asset Life</b>										
Weighted average remaining asset life	24.7	25.6	24.7	20.9	33.1	29.9	20.3	16.4	—	(years)
Weighted average expected total asset life	67.5	49.2	40.2	45.8	48.3	50.0	35.8	17.1	—	(years)

Company Name **Aurora Energy Limited**  
For Year Ended **31 March 2015**

## SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section

sch ref

### 5a(i): Regulatory Tax Allowance

(\$000)

#### Regulatory profit / (loss) before tax

23,704

- plus* Income not included in regulatory profit / (loss) before tax but taxable  
Expenditure or loss in regulatory profit / (loss) before tax but not deductible  
Amortisation of initial differences in asset values  
Amortisation of revaluations

1,957

\*

(19)

\*

3,128

915

5,981

- less* Total revaluations  
Income included in regulatory profit / (loss) before tax but not taxable  
Discretionary discounts and customer rebates  
Expenditure or loss deductible but not in regulatory profit / (loss) before tax  
Notional deductible interest

273

—

\*

—

\*

—

8,766

9,038

#### Regulatory taxable income

20,647

- less* Utilised tax losses  
Regulatory net taxable income

—

20,647

Corporate tax rate (%)

28%

#### Regulatory tax allowance

5,781

\* Workings to be provided in Schedule 14

### 5a(ii): Disclosure of Permanent Differences

In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).

### 5a(iii): Amortisation of Initial Difference in Asset Values

(\$000)

- Opening unamortised initial differences in asset values  
*less* Amortisation of initial differences in asset values  
*plus* Adjustment for unamortised initial differences in assets acquired  
*less* Adjustment for unamortised initial differences in assets disposed  
Closing unamortised initial differences in asset values

85,834

3,128

(6,804)

—

75,902

Opening weighted average remaining useful life of relevant assets (years)

27

Company Name **Aurora Energy Limited**  
 For Year Ended **31 March 2015**

## SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section

sch ref

### 5a(iv): Amortisation of Revaluations

(\$000)

Opening sum of RAB values without revaluations

301,664

Adjusted depreciation

11,026

Total depreciation

11,941

Amortisation of revaluations

915

### 5a(v): Reconciliation of Tax Losses

(\$000)

Opening tax losses

—

plus Current period tax losses

—

less Utilised tax losses

—

Closing tax losses

—

### 5a(vi): Calculation of Deferred Tax Balance

(\$000)

Opening deferred tax

(1,920)

plus Tax effect of adjusted depreciation

3,087

less Tax effect of tax depreciation

4,341

plus Tax effect of other temporary differences\*

553

less Tax effect of amortisation of initial differences in asset values

876

plus Deferred tax balance relating to assets acquired in the disclosure year

1,905

less Deferred tax balance relating to assets disposed in the disclosure year

—

plus Deferred tax cost allocation adjustment

(0)

Closing deferred tax

(1,592)

### 5a(vii): Disclosure of Temporary Differences

*In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).*

### 5a(viii): Regulatory Tax Asset Base Roll-Forward

(\$000)

Opening sum of regulatory tax asset values

170,730

less Tax depreciation

15,503

plus Regulatory tax asset value of assets commissioned

24,102

less Regulatory tax asset value of asset disposals

—

plus Lost and found assets adjustment

—

plus Adjustment resulting from asset allocation

—

plus Other adjustments to the RAB tax value

—

Closing sum of regulatory tax asset values

179,329

Company Name **Aurora Energy Limited**  
 For Year Ended **31 March 2015**

## SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with section 2.3.6 and 2.3.7 of the ID determination.

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

### 5b(i): Summary—Related Party Transactions

(\$000)

Total regulatory income	92
Operational expenditure	20,533
Capital expenditure	13,195
Market value of asset disposals	—
Other related party transactions	—

### 5b(ii): Entities Involved in Related Party Transactions

Name of related party	Related party relationship
Delta Utility Services Ltd	Sister Company - Provides Asset Management and Electrical Contracting (Opex and Capex)
Dunedin City Holdings Ltd	Dunedin City Holdings holds 100% of the Shares in Aurora Energy Ltd and Delta Utility Services
Dunedin City Council	Dunedin City Council holds 100% of the shares in Dunedin City Holding Ltd

\* include additional rows if needed

### 5b(iii): Related Party Transactions

Name of related party	Related party transaction type	Description of transaction	Value of transaction (\$000)	Basis for determining value
Delta Utility Services Ltd	Sales	Recovery of Service Failure Payments	92	ID clause 2.3.7(2)(c)
Dunedin City Council	Opex	Rates Expense	689	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	Service Interruptions and Emergencies in accordance with Asset Management Agreement	3,586	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	Service Interruptions and Emergencies - repair of equipment damaged by 3rd parties	437	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	On going Vegetation Management in accordance with Asset Management Agreement	3,619	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	On going routine inspection and maintenance work in accordance with Asset Management Agreement	4,039	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	On going asset replacement and renewal work in accordance with Asset Management Agreement	395	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	Underground conversion costs	181	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	On going system operation, support and management in accordance with Asset Management Agreement	3,857	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	On going Business support operations in accordance with Asset Management Agreement	2,860	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	On going general management, administration and accountint services in accordance with Administration Agreeer	508	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	Miscelanious work associated with processing of easements and ad-hoc advise	314	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Opex	For lease of CPD metering equipment	48	ID clause 2.3.6(1)(c)(i)
Delta Utility Services Ltd	Capex	Installation of New Network Equipment	6,653	IM clause 2.2.11(5)(g)
Delta Utility Services Ltd	Capex	Installation of New Network Equipment	6,542	IM clause 2.2.11(5)(f)

\* include additional rows if needed

Company Name **Aurora Energy Limited**  
 For Year Ended **31 March 2015**

### SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

This schedule is only to be completed if, as at the date of the most recently published financial statements, the weighted average original tenor of the debt portfolio (both qualifying debt and non-qualifying debt) is greater than five years.  
 This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

#### 5c(i): Qualifying Debt (may be Commission only)

Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Cost of executing an interest rate swap	Debt issue cost readjustment
* include additional rows if needed						–	–	–	–

#### 5c(ii): Attribution of Term Credit Spread Differential

Gross term credit spread differential

–

Total book value of interest bearing debt

Leverage

44%

Average opening and closing RAB values

Attribution Rate (%)

–

Term credit spread differential allowance

–

This schedule provides information on the allocation of operational costs. EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any reclassifications. This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

		Value allocated (\$'000s)			
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase (\$'000s)
<b>Service interruptions and emergencies</b>					
Directly attributable		4,115			
Not directly attributable		–		–	
<b>Total attributable to regulated service</b>		4,115			
<b>Vegetation management</b>					
Directly attributable		3,619			
Not directly attributable		–		–	
<b>Total attributable to regulated service</b>		3,619			
<b>Routine and corrective maintenance and inspection</b>					
Directly attributable		4,039			
Not directly attributable		–		–	
<b>Total attributable to regulated service</b>		4,039			
<b>Asset replacement and renewal</b>					
Directly attributable		582			
Not directly attributable		–		–	
<b>Total attributable to regulated service</b>		582			
<b>System operations and network support</b>					
Directly attributable		3,857			
Not directly attributable		–		–	
<b>Total attributable to regulated service</b>		3,857			
<b>Business support</b>					
Directly attributable		7,396			
Not directly attributable		–		–	
<b>Total attributable to regulated service</b>		7,396			
<b>Operating costs directly attributable</b>		23,608			
<b>Operating costs not directly attributable</b>	–	–	–	–	–
<b>Operational expenditure</b>		23,608			

Company Name **Aurora Energy Limited**  
 For Year Ended **31 March 2015**

## SCHEDULE 5d: REPORT ON COST ALLOCATIONS

This schedule provides information on the allocation of operational costs. EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any reclassifications. This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

### 39 5d(ii): Other Cost Allocations

#### 40 Pass through and recoverable costs

(\$000)

#### 41 Pass through costs

42 Directly attributable

1,469

43 Not directly attributable

—

44 Total attributable to regulated service

1,469

#### 45 Recoverable costs

46 Directly attributable

33,014

47 Not directly attributable

—

48 Total attributable to regulated service

33,014

### 50 5d(iii): Changes in Cost Allocations\* †

#### 52 Change in cost allocation 1

53 Cost category

54 Original allocator or line items

55 New allocator or line items

57 Rationale for change

(\$000)

CY-1 Current Year (CY)

Original allocation

New allocation

Difference

—

—

#### 61 Change in cost allocation 2

62 Cost category

63 Original allocator or line items

64 New allocator or line items

66 Rationale for change

(\$000)

CY-1 Current Year (CY)

Original allocation

New allocation

Difference

—

—

#### 70 Change in cost allocation 3

71 Cost category

72 Original allocator or line items

73 New allocator or line items

75 Rationale for change

(\$000)

CY-1 Current Year (CY)

Original allocation

New allocation

Difference

—

—

\* a change in cost allocation must be completed for each cost allocator change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or component.

† include additional rows if needed



Company Name  
For Year Ended

**Aurora Energy Limited**  
**31 March 2015**

**SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS**

This schedule requires information on the allocation of asset values. This information supports the calculation of the RAB value in Schedule 4. EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any changes in asset allocations. This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

**7 5e(i): Regulated Service Asset Values**

	Value allocated (\$000s) Electricity distribution services
<b>Subtransmission lines</b>	
Directly attributable	13,657
Not directly attributable	
<b>Total attributable to regulated service</b>	13,657
<b>Subtransmission cables</b>	
Directly attributable	9,096
Not directly attributable	
<b>Total attributable to regulated service</b>	9,096
<b>Zone substations</b>	
Directly attributable	59,008
Not directly attributable	
<b>Total attributable to regulated service</b>	59,008
<b>Distribution and LV lines</b>	
Directly attributable	49,274
Not directly attributable	
<b>Total attributable to regulated service</b>	49,274
<b>Distribution and LV cables</b>	
Directly attributable	124,892
Not directly attributable	
<b>Total attributable to regulated service</b>	124,892
<b>Distribution substations and transformers</b>	
Directly attributable	51,201
Not directly attributable	
<b>Total attributable to regulated service</b>	51,201
<b>Distribution switchgear</b>	
Directly attributable	19,588
Not directly attributable	
<b>Total attributable to regulated service</b>	19,588
<b>Other network assets</b>	
Directly attributable	3,881
Not directly attributable	
<b>Total attributable to regulated service</b>	3,881
<b>Non-network assets</b>	
Directly attributable	
Not directly attributable	
<b>Total attributable to regulated service</b>	—
<b>Regulated service asset value directly attributable</b>	330,597
<b>Regulated service asset value not directly attributable</b>	—
<b>Total closing RAB value</b>	330,597

**51 5e(ii): Changes in Asset Allocations\* †**

			(\$000)	
			CY-1	Current Year (CY)
<b>Change in asset value allocation 1</b>				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	—	—
Rationale for change				
<b>Change in asset value allocation 2</b>				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	—	—
Rationale for change				
<b>Change in asset value allocation 3</b>				
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	—	—
Rationale for change				

\* a change in asset allocation must be completed for each allocator or component change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or component.

† include additional rows if needed

Company Name

Aurora Energy Limited

For Year Ended

31 March 2015

**SCHEDULE 6a: REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR**

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.

EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7	<b>6a(i): Expenditure on Assets</b>	(\$000)	(\$000)
8	Consumer connection		10,250
9	System growth		6,898
10	Asset replacement and renewal		7,501
11	Asset relocations		2,570
12	Reliability, safety and environment:		
13	Quality of supply	1,541	
14	Legislative and regulatory	–	
15	Other reliability, safety and environment	402	
16	<b>Total reliability, safety and environment</b>		1,943
17	<b>Expenditure on network assets</b>		29,162
18	Expenditure on non-network assets		–
19			
20	<b>Expenditure on assets</b>		29,162
21	plus Cost of financing		–
22	less Value of capital contributions		4,434
23	plus Value of vested assets		–
24			
25	<b>Capital expenditure</b>		24,728
26	<b>6a(ii): Subcomponents of Expenditure on Assets (where known)</b>		(\$000)
27	Energy efficiency and demand side management, reduction of energy losses		–
28	Overhead to underground conversion		300
29	Research and development		–
30	<b>6a(iii): Consumer Connection</b>		
31	Consumer types defined by EDB*	(\$000)	(\$000)
32	[EDB consumer type]	10,250	
33	[EDB consumer type]		
34	[EDB consumer type]		
35	[EDB consumer type]		
36	[EDB consumer type]		
37	* include additional rows if needed		
38	<b>Consumer connection expenditure</b>		10,250
39			
40	less Capital contributions funding consumer connection expenditure	3,584	
41	<b>Consumer connection less capital contributions</b>		6,666
42	<b>6a(iv): System Growth and Asset Replacement and Renewal</b>		
43			
44			
45	Subtransmission	–	628
46	Zone substations	6,654	1,486
47	Distribution and LV lines	125	4,222
48	Distribution and LV cables	43	311
49	Distribution substations and transformers	34	616
50	Distribution switchgear	39	193
51	Other network assets	3	45
52	<b>System growth and asset replacement and renewal expenditure</b>	6,898	7,501
53	less Capital contributions funding system growth and asset replacement and renewal	17	–
54	<b>System growth and asset replacement and renewal less capital contributions</b>	6,881	7,501
55			
56	<b>6a(v): Asset Relocations</b>		
57	Project or programme*	(\$000)	(\$000)
58	CFR 7472 -Omakau Line deviation Simpsons farm	329	
59	CFR 7490 Adams Spiers Irrigation Scheme	356	
60	CFR 7482 33kv Subtransmission Diversion Feeder Shotover Country	196	
61	CFR 7524 Changeover from Telecom Poles	180	
62	CFR 6770 Cardrona Village underground conversion Project	300	
63	* include additional rows if needed		
64	All other projects or programmes - asset relocations	1,209	
65	<b>Asset relocations expenditure</b>		2,570
66	less Capital contributions funding asset relocations	833	
67	<b>Asset relocations less capital contributions</b>		1,737

Company Name

Aurora Energy Limited

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31 March 2015

**SCHEDULE 6a: REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR**

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.

EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

**6a(vi): Quality of Supply**

Project or programme\*

CFR 6974 - Melville St no 1 Transformer replacement

CFR 7087 - Clyde Dam Slip

CFR 6899 - SC1 &amp; Sc 7 HV Feeder Tie

CFR 7547 - New Feeder 2751 Golf Course Road

[Description of material project or programme]

\* include additional rows if needed

All other projects programmes - quality of supply

**Quality of supply expenditure**

less Capital contributions funding quality of supply

**Quality of supply less capital contributions**

(\$000)

(\$000)

265

166

173

111

826

1,541

-

1,541

**6a(vii): Legislative and Regulatory**

Project or programme\*

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

\* include additional rows if needed

All other projects or programmes - legislative and regulatory

**Legislative and regulatory expenditure**

less Capital contributions funding legislative and regulatory

**Legislative and regulatory less capital contributions**

(\$000)

(\$000)

-

-

-

-

-

-

-

-

-

**6a(viii): Other Reliability, Safety and Environment**

Project or programme\*

CFR 6818 - Low Span Centennial Avenue

CFR 7619 Pole Crown range

CFR 7178 - High way crossing low span tarras cromwell highway

CFR 7316 - provide isolations &amp; remove asbestos

CFR 7421 - Leith valley road

\* include additional rows if needed

All other projects or programmes - other reliability, safety and environment

**Other reliability, safety and environment expenditure**

less Capital contributions funding other reliability, safety and environment

**Other reliability, safety and environment less capital contributions**

(\$000)

(\$000)

53

30

20

16

15

268

402

-

402

**6a(ix): Non-Network Assets****Routine expenditure**

Project or programme\*

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

\* include additional rows if needed

All other projects or programmes - routine expenditure

**Routine expenditure****Atypical expenditure**

Project or programme\*

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

[Description of material project or programme]

\* include additional rows if needed

All other projects or programmes - atypical expenditure

**Atypical expenditure****Expenditure on non-network assets**

(\$000)

(\$000)

-

-

-

-

-

-

-

-

-

-

-

-

-

-

-

-

-

-

-

Company Name

Aurora Energy Limited

For Year Ended

31 March 2015

**SCHEDULE 6b: REPORT ON OPERATIONAL EXPENDITURE FOR THE DISCLOSURE YEAR**

This schedule requires a breakdown of operational expenditure incurred in the disclosure year.

EDBs must provide explanatory comment on their operational expenditure in Schedule 14 (Explanatory notes to templates). This includes explanatory comment on any atypical operational expenditure and assets replaced or renewed as part of asset replacement and renewal operational expenditure, and additional information on insurance.

This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

		(\$000)	(\$000)
7	<b>6b(i): Operational Expenditure</b>		
8	Service interruptions and emergencies	4,115	
9	Vegetation management	3,619	
10	Routine and corrective maintenance and inspection	4,039	
11	Asset replacement and renewal	582	
12	<b>Network opex</b>		12,355
13	System operations and network support	3,857	
14	Business support	7,396	
15	<b>Non-network opex</b>		11,253
16			
17	<b>Operational expenditure</b>		23,608
18	<b>6b(ii): Subcomponents of Operational Expenditure (where known)</b>		
19	Energy efficiency and demand side management, reduction of energy losses		—
20	Direct billing*		—
21	Research and development		—
22	Insurance		258
23	* Direct billing expenditure by suppliers that directly bill the majority of their consumers		

Company Name **Aurora Energy Limited**  
 For Year Ended **31 March 2015**

## SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.

EDBs must provide explanatory comment on the variance between actual and target revenue and forecast expenditure in Schedule 14 (Mandatory Explanatory Notes). This information is part of the audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8. For the purpose of this audit, target revenue and forecast expenditures only need to be verified back to previous disclosures.

sch ref

7	<b>7(i): Revenue</b>	<b>Target (\$000) <sup>1</sup></b>	<b>Actual (\$000)</b>	<b>% variance</b>
8	Line charge revenue	89,870	90,830	1%
9	<b>7(ii): Expenditure on Assets</b>	<b>Forecast (\$000) <sup>2</sup></b>	<b>Actual (\$000)</b>	<b>% variance</b>
10	Consumer connection	5,270	10,250	95%
11	System growth	8,775	6,898	(21%)
12	Asset replacement and renewal	11,036	7,501	(32%)
13	Asset relocations	1,219	2,570	111%
14	Reliability, safety and environment:			
15	Quality of supply	1,873	1,541	(18%)
16	Legislative and regulatory		–	–
17	Other reliability, safety and environment	2,093	402	(81%)
18	<b>Total reliability, safety and environment</b>	3,966	1,943	(51%)
19	<b>Expenditure on network assets</b>	30,266	29,162	(4%)
20	Expenditure on non-network assets		–	–
21	Expenditure on assets	30,266	29,162	(4%)
22	<b>7(iii): Operational Expenditure</b>			
23	Service interruptions and emergencies	3,330	4,115	24%
24	Vegetation management	4,333	3,619	(16%)
25	Routine and corrective maintenance and inspection	5,468	4,039	(26%)
26	Asset replacement and renewal	245	582	138%
27	<b>Network opex</b>	13,376	12,355	(8%)
28	System operations and network support	4,824	3,857	(20%)
29	Business support	4,906	7,396	51%
30	<b>Non-network opex</b>	9,730	11,253	16%
31	<b>Operational expenditure</b>	23,106	23,608	2%
32	<b>7(iv): Subcomponents of Expenditure on Assets (where known)</b>			
33	Energy efficiency and demand side management, reduction of energy losses	–	–	–
34	Overhead to underground conversion	–	300	–
35	Research and development	–	–	–
36				
37	<b>7(v): Subcomponents of Operational Expenditure (where known)</b>			
38	Energy efficiency and demand side management, reduction of energy losses	–	–	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	–	258	–
42				
43	<i>1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination</i>			
44	<i>2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)</i>			

Company Name  
For Year Ended  
Network / Sub-Network Name

**Aurora Energy Limited**  
**31 March 2015**  
**Total Business**

**SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES**

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

sch ref

**8(i): Billed Quantities by Price Component**

					Price component	Billed quantities by price component											
					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)	
Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)		LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW	
Standard Domestic	Standard domestic	Standard	71,295	572,165		71,295	—	572,164,669	—	—	—	—	—	572,164,669	—	—	
Load Group 0	other	Standard	353	36		353							353				
Load Group 0A	other	Standard	493	988		493			988				493			988	
Load Group 1A	other	Standard	787	2,380		787			6,301	1,103					6,301	1,103	
Load Group 1	other	Standard	5,592	40,363		5,592			83,905	18,572					83,905	18,572	
Load Group 2	other	Standard	5,995	257,553		5,995			313,120	63,338	(6)				313,120	63,338	
Load Group 2	other	Non-standard	3	113		3			220						220		
Load Group 3	other	Standard	196	53,443		196			40,551	557,669	11,984	—			40,551	11,984	
Load Group 3	other	Non-standard	2	641		2			400	5,195		(280)			400		
Load Group 3A	other	Standard	153	79,511		153			50,339	536,728	16,623	(210)			50,339	16,623	
Load Group 3A	other	Non-standard	2	1,549		2			800	19,511		(280)			800		
Load Group 4	other	Standard	117	169,726		117			87,882	982,286	30,448	68,360			87,882	30,448	
Load Group 4	other	Non-standard	1	911		1							1				
Load Group 5	other	Standard	6	55,986		6			32,223	241,957	8,271	13,575			32,223	8,271	
Load Group 5	other	Non-standard	1	2,856		1							1				
Street Lighting	other	Standard	11	10,047		11	6,421	10,047,276					11	10,047,276			
Add extra rows for additional consumer groups or price category codes as necessary																	
Standard consumer totals			84,998	1,242,064		84,998	6,421	582,211,945	615,308	2,318,640	150,340	81,719	857	582,211,945	615,308	150,340	
Non-standard consumer totals			9	6,070		9	—	—	1,420	24,706	—	(560)	2	—	1,420	—	
Total for all consumers			85,007	1,248,134		85,007	6,421	582,211,945	616,728	2,343,346	150,340	81,159	859	582,211,945	616,728	150,340	

Add extra columns for additional billed quantities by price component as necessary

Company Name  
For Year Ended  
Network / Sub-Network Name

**Aurora Energy Limited**  
**31 March 2015**  
**Total Business**

**SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES**

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

**8(ii): Line Charge Revenues (\$000) by Price Component****Line charge revenues (\$000) by price component**

Price component

Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
\$ / annum	\$ / lamp	\$ / kWh	\$ / kVA	\$ / kVA x km	\$ / kW	\$ / kVA	\$ / annum	\$ / kWh	\$ / kVA	\$ / kW
\$3,876		\$29,906						\$16,043		
\$53							\$28		—	—
\$150			\$0				\$85		\$0	\$0
\$9			\$124			\$91			\$44	\$82
\$65			\$1,490			\$1,528			\$482	\$1,436
\$139			\$5,942			\$5,232 (\$6)			\$397	\$4,816
\$0			\$6			\$0	—		\$0	\$0
\$89			\$1,118	\$209	\$787	(\$0)			\$162	\$958
\$1			\$13	\$2		(\$3)			\$0	
\$68			\$1,300	\$195	\$1,023	(\$3)			\$284	\$1,401
\$1			\$23	\$7		(\$3)			\$1	
\$130			\$1,421	\$352	\$1,708	\$573			\$317	\$2,721
\$47							\$43			
\$8		\$1	\$227	\$69	\$281	\$117		\$1	\$94	\$895
\$55							\$90			
\$257	\$85	\$78					\$127	\$44		
\$4,843	\$85	\$29,985	\$11,622	\$826	\$10,640	\$682	\$240	\$16,087	\$1,731	\$12,310
\$104	—	—	\$42	\$9	\$0	(\$7)	\$133	—	\$1	\$0
\$4,948	\$85	\$29,985	\$11,664	\$835	\$10,640	\$675	\$373	\$16,087	\$1,732	\$12,310

Add extra columns for additional line charge revenues by price component as necessary

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)
Standard Domestic	Standard domestic	Standard	\$49,824	
Load Group 0	other	Standard	\$81	
Load Group 0A	other	Standard	\$235	
Load Group 1A	other	Standard	\$224	
Load Group 1	other	Standard	\$3,082	\$1,908
Load Group 2	other	Standard	\$16,510	
Load Group 2	other	Non-standard	\$7	
Load Group 3	other	Standard	\$3,323	
Load Group 3	other	Non-standard	\$13	
Load Group 3A	other	Standard	\$4,220	
Load Group 3A	other	Non-standard	\$29	
Load Group 4	other	Standard	\$7,223	
Load Group 4	other	Non-standard	\$90	
Load Group 5	other	Standard	\$1,694	
Load Group 5	other	Non-standard	\$145	
Street Lighting	other	Standard	\$590	
Add extra rows for additional consumer groups or price category codes as necessary				
Standard consumer totals			\$89,051	—
Non-standard consumer totals			\$283	—
Total for all consumers			\$89,333	—

Total distribution line charge revenue	Total transmission line charge revenue (if available)	Rate (eg, \$ per day, \$ per kWh, etc.)
\$33,782	\$16,043	
\$53	\$28	
\$150	\$86	
\$224	\$125	
\$3,082	\$1,908	
\$11,297	\$5,214	
\$6	\$0	
\$2,203	\$1,120	
\$12	\$0	
\$2,584	\$1,636	
\$28	\$1	
\$4,185	\$3,039	
\$47	\$43	
\$704	\$989	
\$55	\$90	
\$419	\$171	
\$58,684	\$30,367	
\$149	\$134	
\$58,832	\$30,501	

**8(iii): Number of ICPs directly billed**

Number of directly billed ICPs at year end

0

Check **OK**

Company Name  
For Year Ended  
Network / Sub-Network Name

**Aurora Energy Limited**  
**31 March 2015**  
**Dunedin**

**SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES**

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

sch ref

**8(i): Billed Quantities by Price Component**

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Standard domestic	Standard domestic	Standard	550	2,798
Load Group 0	other	Standard	46,790	387,825
Load Group 0A	other	Standard	138	3
Load Group 1A	other	Standard	129	158
Load Group 1	other	Standard	398	1,167
Load Group 2	other	Standard	2,972	20,810
Load Group 3	other	Standard	3,028	133,388
Load Group 3A	other	Standard	102	31,918
Load Group 4	other	Standard	86	52,278
Load Group 5	other	Standard	77	113,224
Street Lighting	other	Standard	7	55,740
Add extra rows for additional consumer groups or price category codes as necessary			2	7211.032
Standard consumer totals			54,277	799,308
Non-standard consumer totals			—	—
Total for all consumers			54,277	799,308

Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)

**Billed quantities by price component**

Price Component	Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
	LS	Lamp	kWh	kVA	kVA x km	kW	kVA	LS	kWh	kVA	kW
	47,340		390,622,902						390,622,902		
	138							138			
	129							129			
	398			3,186		382				3,186	382
	2,972			44,591		7,184				44,591	7,184
	3,028			152,946		24,648	(6)			152,946	24,648
	102			20,125	111,377	5,803				20,125	5,803
	86			27,089	147,520	8,780	(210)			27,089	8,780
	77			58,778	323,681	17,351	48,966			58,778	17,351
	7			30,557	221,157	7,988	13,575			30,557	7,988
	2							2			
	54,279	--	390,622,902	337,271	803,735	72,136	62,325	269	390,622,902	337,271	72,136
	--	--	--	--	--	--	--	--	--	--	--
	54,279	--	390,622,902	337,271	803,735	72,136	62,325	269	390,622,902	337,271	72,136

Add extra columns for additional billed quantities by price component as necessary



Company Name  
For Year Ended  
Network / Sub-Network Name

**Aurora Energy Limited**  
**31 March 2015**  
**Dunedin**

**SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES**

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

**8(ii): Line Charge Revenues (\$000) by Price Component****Line charge revenues (\$000) by price component**

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)
Standard domestic	Standard domestic	Standard	\$27,029	
Load Group 0	other	Standard	\$26	
Load Group 0A	other	Standard	\$52	
Load Group 1A	other	Standard	\$149	
Load Group 1	other	Standard	\$2,300	
Load Group 2	other	Standard	\$7,610	
Load Group 3	other	Standard	\$1,608	
Load Group 3A	other	Standard	\$2,249	
Load Group 4	other	Standard	\$4,463	
Load Group 5	other	Standard	\$1,619	
Street Lighting	other	Standard	\$384	

Add extra rows for additional consumer groups or price category codes as necessary

Standard consumer totals	\$47,489	—
Non-standard consumer totals	—	—
Total for all consumers	\$47,489	—

Total distribution line charge revenue	Total transmission line charge revenue (if available)	Rate (eg, \$ per day, \$ per kWh, etc.)
\$16,742	\$10,287	
\$15	\$11	
\$29	\$23	
\$80	\$69	
\$1,191	\$1,109	
\$4,627	\$2,983	
\$889	\$719	
\$1,175	\$1,073	
\$2,350	\$2,113	
\$676	\$943	
\$257	\$127	

\$28,031	\$19,459
—	—
\$28,031	\$19,459

Check **OK**

Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
\$ / annum	\$ / lamp	\$ / kWh	\$ / kVA	\$ / kVA x km	\$ / kW	\$ / kVA	\$ / annum	\$ / kWh	\$ / kVA	\$ / kW
\$2,570		\$14,172						\$10,287		
\$15							\$11			
\$29							\$23			
\$4			\$40			\$36			\$27	\$42
\$30			\$489			\$672			\$315	\$795
\$67			\$2,256			\$2,305	(\$9)		\$255	\$2,727
\$41			\$497	\$31		\$320			\$90	\$629
\$35			\$617	\$41		\$485	(\$9)		\$121	\$952
\$78			\$850	\$91		\$926	\$405		\$232	\$1,882
\$8			\$221	\$62		\$267	\$117		\$77	\$867
\$257							\$127			
\$3,134	—	\$14,172	\$4,969	\$225	\$5,010	\$520	\$162	\$10,287	\$1,116	\$7,894
—	—	—	—	—	—	—	—	—	—	—
\$3,134	—	\$14,172	\$4,969	\$225	\$5,010	\$520	\$162	\$10,287	\$1,116	\$7,894

Add extra columns for additional line charge revenues by price component as necessary

**8(iii): Number of ICPs directly billed**

Number of directly billed ICPs at year end

N/A

sch ref

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

## 9

10

Add extra columns for additional billed quantities by price component as necessary

Company Name **Aurora Energy Limited**  
 For Year Ended **31 March 2015**  
 Network / Sub-Network Name **Central Otago**

**SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES**

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

**8(ii): Line Charge Revenues (\$000) by Price Component****Line charge revenues (\$000) by price component**

Price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)
Standard Domestic	Standard domestic	Standard	\$22,733	
Load Group 0	other	Standard	\$53	
Load Group 0A	other	Standard	\$183	
Load Group 1A	other	Standard	\$200	
Load Group 1	other	Standard	\$2,699	
Load Group 2	other	Standard	\$8,900	
Load Group 2	other	Non-standard	\$7	
Load Group 3	other	Standard	\$1,715	
Load Group 3	other	Non-standard	\$13	
Load Group 3A	other	Standard	\$1,409	
Load Group 3A	other	Non-standard	\$28	
Load Group 4	other	Standard	\$2,760	
Load Group 4	other	Non-standard	\$90	
Load Group 5	other	Standard	\$72	
Load Group 5	other	Non-standard	\$145	
Street Lighting	other	Standard	\$207	
Add extra rows for additional consumer groups or price category codes as necessary				
Standard consumer totals			\$41,495	–
Non-standard consumer totals			\$283	–
Total for all consumers			\$41,777	–

Total distribution line charge revenue	Total transmission line charge revenue (if available)	Rate (eg, \$ per day, \$ per kWh, etc.)
\$16,996	\$5,737	
\$38	\$16	
\$121	\$62	
\$144	\$56	
\$1,400	\$89	
\$6,669	\$2,231	
\$6	\$0	
\$1,314	\$401	
\$12	\$0	
\$1,409	\$562	
\$28	\$1	
\$1,835	\$825	
\$47	\$43	
\$27	\$45	
\$55	\$90	
\$163	\$44	
\$30,606	\$10,889	
\$149	\$134	
\$30,755	\$11,023	

Fixed (Distribution)	Fixed (Distribution)	Energy Delivery (Distribution)	Capacity (Distribution)	Capacity - Distance (Distribution)	Control Period Demand (Distribution)	Transformer Lease Other Charges & Rebates (Distribution)	Fixed (Transmission)	Energy Delivery (Transmission)	Capacity (Transmission)	Control Period Demand (Distribution)
\$ / annum	\$ / lamp	\$ / kWh	\$ / kVA	\$ / kVA x km	\$ / kW	\$ / kVA	\$ / annum	\$ / kWh	\$ / kVA	\$ / kW
\$1,301	–	\$15,695	–	–	–	–	–	\$5,737	–	–
\$38							\$16			
\$121							\$62			
\$5			\$84		\$55			\$17		\$39
\$34			\$1,000		\$86			\$168		\$641
\$72			\$3,686		\$2,917	(\$6)		\$142		\$2,089
\$0			\$6		\$0	–		\$0		\$0
\$48			\$621	\$178	\$467	(\$0)		\$72		\$329
\$1			\$13	\$2		(\$3)		\$0		
\$33			\$683	\$154	\$539	(\$0)		\$114		\$449
\$1			\$23	\$7		(\$3)		\$1		
\$52			\$572	\$261	\$783	\$168		\$86		\$840
\$47							\$43			
\$0			\$5	\$7	\$14	–		\$17		\$28
\$55							\$90			
	\$85	\$78						\$44		
\$1,703	\$85	\$15,773	\$6,652	\$601	\$5,630	\$161	\$78	\$5,781	\$615	\$4,415
\$104	–	–	\$42	\$9	\$0	(\$7)	\$133	–	\$1	\$0
\$1,808	\$85	\$15,773	\$6,694	\$610	\$5,630	\$155	\$211	\$5,781	\$616	\$4,415

Add extra columns for additional line charge revenues by price component as necessary

**8(iii): Number of ICPs directly billed**

Number of directly billed ICPs at year end

0

Check **OK**

Company Name	<b>Aurora Energy Limited</b>
For Year Ended	<b>31 March 2015</b>
Network / Sub-network Name	<b>Total Business</b>

**SCHEDULE 9a: ASSET REGISTER**

This schedule requires a summary of the quantity of assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

					Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1-4)
8	Voltage	Asset category	Asset class	Units				
9	All	Overhead Line	Concrete poles / steel structure	No.	20,820	21,427	607	4
10	All	Overhead Line	Wood poles	No.	33,016	32,376	(640)	4
11	All	Overhead Line	Other pole types	No.	—	—	—	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	513	513	—	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	—	—	—	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	19	19	—	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	—	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	36	36	—	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	—	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	—	—	—	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	—	—	—	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	—	—	—	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	—	—	—	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	—	—	—	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	28	29	1	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	—	—	—	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	—	—	—	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	3	5	2	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	—	—	—	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	233	236	3	4
29	HV	Zone substation switchgear	33kV RMU	No.	—	—	—	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	—	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	53	53	—	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	345	347	2	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	15	15	—	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	66	67	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,323	2,319	(4)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	—	—	—	N/A
37	HV	Distribution Line	SWER conductor	km	9	9	—	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	486	526	40	4
39	HV	Distribution Cable	Distribution UG PILC	km	430	430	—	4
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	1	—	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	42	41	(1)	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	14	11	(3)	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	6,353	6,420	67	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	952	975	23	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	532	547	15	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,155	4,152	(3)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	2,576	2,666	90	4
48	HV	Distribution Transformer	Voltage regulators	No.	39	40	1	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	2,576	2,666	90	4
50	LV	LV Line	LV OH Conductor	km	1,051	1,050	(1)	4
51	LV	LV Cable	LV UG Cable	km	856	877	21	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	219	220	1	4
53	LV	Connections	OH/UG consumer service connections	No.	84,935	85,863	928	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	478	478	—	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	96	97	1	4
56	All	Capacitor Banks	Capacitors including controls	No.	3	3	—	4
57	All	Load Control	Centralised plant	Lot	6	6	—	4
58	All	Load Control	Relays	No.	2,203	2,205	2	4
59	All	Civils	Cable Tunnels	km	—	—	—	N/A

Company Name	<b>Aurora Energy Limited</b>
For Year Ended	<b>31 March 2015</b>
Network / Sub-network Name	<b>Dunedin</b>

**SCHEDULE 9a: ASSET REGISTER**

This schedule requires a summary of the quantity of assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

					Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1-4)
8	Voltage	Asset category	Asset class	Units				
9	All	Overhead Line	Concrete poles / steel structure	No.	14,013	14,286	273	4
10	All	Overhead Line	Wood poles	No.	15,141	14,869	(272)	4
11	All	Overhead Line	Other pole types	No.	—	—	—	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	144	144	—	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	—	—	—	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	4	4	—	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	25	25	—	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	36	36	—	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	11	11	—	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	—	—	—	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	—	—	—	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	—	—	—	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	—	—	—	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	—	—	—	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	18	18	—	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	—	—	—	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	—	—	—	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	—	—	—	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	—	—	—	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	111	111	—	4
29	HV	Zone substation switchgear	33kV RMU	No.	—	—	—	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	—	—	—	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	23	23	—	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	262	262	—	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	—	—	—	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	35	35	—	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	730	731	1	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	—	—	—	N/A
37	HV	Distribution Line	SWER conductor	km	9	9	—	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	29	30	1	4
39	HV	Distribution Cable	Distribution UG PILC	km	281	281	—	4
40	HV	Distribution Cable	Distribution Submarine Cable	km	1	1	—	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	11	11	—	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	13	9	(4)	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2,534	2,553	19	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	460	464	4	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	306	314	8	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	1,707	1,713	6	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	896	906	10	4
48	HV	Distribution Transformer	Voltage regulators	No.	13	11	(2)	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	896	906	10	4
50	LV	LV Line	LV OH Conductor	km	825	824	(1)	4
51	LV	LV Cable	LV UG Cable	km	246	251	5	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	150	150	—	4
53	LV	Connections	OH/UG consumer service connections	No.	54,385	54,662	277	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	309	305	(4)	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	39	39	—	4
56	All	Capacitor Banks	Capacitors including controls	No.	3	3	—	4
57	All	Load Control	Centralised plant	Lot	3	3	—	4
58	All	Load Control	Relays	No.	1,120	1,120	—	4
59	All	Civils	Cable Tunnels	km	—	—	—	N/A

Company Name	<b>Aurora Energy Limited</b>
For Year Ended	<b>31 March 2015</b>
Network / Sub-network Name	<b>Central Otago</b>

**SCHEDULE 9a: ASSET REGISTER**

This schedule requires a summary of the quantity of assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

					Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1-4)
8	Voltage	Asset category	Asset class	Units				
9	All	Overhead Line	Concrete poles / steel structure	No.	6,807	7,141	334	4
10	All	Overhead Line	Wood poles	No.	17,875	17,507	(368)	4
11	All	Overhead Line	Other pole types	No.	—	—	—	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	369	369	—	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	—	—	—	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	15	15	—	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	—	—	—	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	—	—	—	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	—	—	—	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	—	—	—	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	—	—	—	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	—	—	—	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	—	—	—	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	—	—	—	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	10	11	1	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	—	—	—	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	—	—	—	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	3	5	2	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	—	—	—	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	122	125	3	4
29	HV	Zone substation switchgear	33kV RMU	No.	—	—	—	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	6	6	—	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	30	30	—	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	83	85	2	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	15	15	—	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	31	32	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,593	1,588	(5)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	—	—	—	N/A
37	HV	Distribution Line	SWER conductor	km	—	—	—	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	456	495	39	4
39	HV	Distribution Cable	Distribution UG PILC	km	148	148	—	4
40	HV	Distribution Cable	Distribution Submarine Cable	km	—	—	—	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	31	30	(1)	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	1	2	1	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	3,819	3,867	48	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	490	509	19	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	225	232	7	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	2,448	2,439	(9)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,675	1,755	80	4
48	HV	Distribution Transformer	Voltage regulators	No.	26	29	3	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	1,675	1,755	80	4
50	LV	LV Line	LV OH Conductor	km	226	226	—	4
51	LV	LV Cable	LV UG Cable	km	604	620	16	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	68	69	1	4
53	LV	Connections	OH/UG consumer service connections	No.	30,468	31,119	651	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	169	173	4	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	57	58	1	4
56	All	Capacitor Banks	Capacitors including controls	No.	—	—	—	4
57	All	Load Control	Centralised plant	Lot	3	3	—	4
58	All	Load Control	Relays	No.	1,078	1,080	2	4
59	All	Civils	Cable Tunnels	km	—	—	—	N/A

Company Name  
For Year Ended  
Network / Sub-network Name

**SCHEDULE 9b: ASSET AGE PROFILE**

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

[illegible]

Company Name  
For Year Ended  
Network / Sub-network Name

**SCHEDULE 9b: ASSET AGE PROFILE**

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

8	Disclosure Year (year ended)		31 March 2015		Number of assets at disclosure year end by installation date																										No. with age unknown	end of year (quantity)	No. with default dates	Data accuracy [1-4]
	Voltage	Asset category	Asset class	Units	pre-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015							
9	All	Overhead Line	Concrete poles / steel structure	No.	-	17	1,612	5,765	2,934	2,140	806	23	11	77	31	11	32	32	23	17	11	30	46	155	159	267	87			14,286	3			
10	All	Overhead Line	Wood poles	No.	1,254	1,486	2,593	3,500	1,258	1,354	1,787	196	128	120	123	93	124	131	114	171	104	92	111	60	48	17	5			14,869	3			
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	62	-	63	14	3	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			144	3			
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	3	-			4	3			
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	22	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			25	3			
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	8	27	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			36	3			
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	9	-	-	-	1	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-			11	3			
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	1	5	3	6	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			18	4			
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-			N/A				
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	40	23	5	-	6	-	-	-	-	-	-	-	-	-	-	2	8	-	25	3	-			111	3			
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	3	-	2	4	-	-	-	-	-	1	-	-	1	2	5	-	-	3	-	2	-	-			23	3			
33	HV	Zone substation switchgear	33/6.6/11/22kV CB (ground mounted)	No.	-	32	46	37	78	2	13	-	-	-	17	-	9	-	-	-	-	11	17	-	-	-	-			262	3			
34	HV	Zone substation switchgear	33/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
35	HV	Zone Substation Transformer	Zone Substation Transformer	No.	-	-	6	10	10	2	2	-	-	-	-	-	-	-	-	-	1	-	2	2	-	-	-			35	3			
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2	35	120	250	138	68	54	5	4	6	5	6	5	1	4	6	5	1	2	-	2	1	1			731	3			
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			N/A				
38	HV	Distribution Line	SWER conductor	km	-	-	6	2	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			9	3			
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	-	-	-	4	2	2	1	3	3	3	2	3	1	1	1	1	2	-	1	-			30	3			
40	HV	Distribution Cable	Distribution UG PILC	km	-	8	36	54	69	50	29	2	1	1	1	2	3	2	1	3	3	6	3	2	3	2	-			281	3			
41	HV	Distribution Cable	Distribution Submarine Cable	km	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			1	3			
42	HV	Distribution switchgear	33/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	-	-	-	1	-	-	-	-	-	1	4	-	-	-	9	1	-	1	-	-			11	4			
43	HV	Distribution switchgear	33/6.6/11/22kV CB (Indoor)	No.	-	3	-	2	-	1	-	-	-	-	-	-	3	-	-	-	-	1	-	-	-	-	-			9	3			
44	HV	Distribution switchgear	33/6.6/11/22kV Switches and fuses (pole mounted)	No.	-	21	74	616	455	436	488	14	19	27	42	29	49	44	29	21	33	18	23	29	29	51	6			2,553	3			
45	HV	Distribution switchgear	33/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	1	10	108	73	73	71	5	9	6	12	3	7	3	7	13	13	21	9	14	2	-	4			464	3			
46	HV	Distribution switchgear	33/6.6/11/22kV RMU	No.	-	-	-	2	44	81	91	7	3	8	4	11	7	3	2	7	6	9	6	3	11	8	3			314	3			
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	-	-	6	218	270	304	511	36	25	48	31	27	38	32	20	15	21	13	21	22	21	18	16			1,713	3			
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	2	70	156	158	215	10	17	22	18	19	31	27	13	19	22	20	21	19	21	22	4			906	3			
49	HV	Distribution Transformer	Voltage regulators	No.	-	-	-	2	5	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			11	3			
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	2	70	156	158	215	10	17	22	18	19	31	27	13	19	22	20	21	19	21	22	4			906	3			
51	LV	LV Line	LV OH Conductor	km	52	26	69	192	169	133	4	2	3	4	3	3	2	2	5	1	3	2	-	2	1	1	2			824	3			
52	LV	LV Cable	LV UG Cable	km	-	-	2	26	42	42	35	3	5	5	6	9	14	9	10	5	7	5	8	6	7	6	3	2			251	3		
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	5	3	4	10	9	10	87	-	-	-	-	1	1	1	1	2	4	2	2	6	1	1	-			150	3			
54	LV	Connections	OH/UG consumer service connections	No.	12,924	3,675	6,923	8,657	6,974	4,496	4,743	289	267	365	430	496	492	509	550	399	390	460	360	401	378	405	79			54,662	3			
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	38	46	39	84	2	14	1	-	-	1	17	-	12	5	2	5	14	18	4	1	2	-			305	3			
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	-	-	13	-	-	2	-	1	1	-	1	-	-	1	-	1	9	3	3	4			39	4			
57	All	Capacitor Banks	Capacitors including controls	Lot	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-			3	4			
58	All	Load Control	Centralised plant	Lot	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-			3	4			
59	All	Load Control	Relays	Lot	1	1	12	176	243	205	312	14	7	12	9	9	12	14	10	9	18	12	21	12	6	3	2			1,120	3			
60	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-			-	N/A			



Company Name  
For Year Ended  
Network / Sub-network Name

Aurora Energy Limited  
31 March 2015  
Central Otago

**SCHEDULE 9b: ASSET AGE PROFILE**

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	Disclosure Year (year ended)		31 March 2015		Number of assets at disclosure year end by installation date																				No. with age unknown	end of year (quantity)	No. with default dates	Data accuracy (1-4)			
	Voltage	Asset category	Asset class	Units	pre-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012					2013	2014	2015
9	All	Overhead Line	Concrete poles / steel structure	No.	—	19	87	432	1,852	1,047	1,040	71	89	124	99	68	86	154	149	197	95	112	186	430	326	411	67	—	7,141	3	
10	All	Overhead Line	Wood poles	No.	—	40	199	5,623	4,729	2,573	1,639	144	104	269	332	223	144	200	178	151	227	251	235	94	52	90	10	—	17,507	3	
12	All	Overhead Line	Other pole types	No.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	3	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	9	3	11	93	72	27	125	—	—	—	—	—	1	6	—	—	—	4	4	11	—	—	3	—	369	N/A	
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	—	—	—	—	—	1	7	—	—	—	—	—	1	1	—	—	1	2	1	—	—	1	—	—	15	3	
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	—	—	—	—	1	3	3	—	—	—	—	—	—	—	—	—	—	1	—	—	1	—	—	1	11	4	
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	0	—	—	—	—	—	—	—	—	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	—	—	—	—	—	—	—	—	—	—	—	3	—	—	—	—	—	—	—	—	—	—	—	2	5	4	
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	—	—	14	3	3	24	18	—	—	—	—	6	2	2	—	26	17	2	1	2	1	—	—	4	125	3	
30	HV	Zone substation switchgear	33kV RMU	No.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	—	—	—	—	—	—	6	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	6	4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	—	—	4	3	—	8	7	—	—	—	—	—	1	—	—	—	—	3	1	—	—	1	2	—	30	3	
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	—	—	—	—	2	7	13	—	—	—	13	—	3	—	9	—	—	5	4	12	2	11	—	4	85	3	
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	—	—	—	4	6	1	—	—	—	—	—	2	2	—	—	—	—	—	—	—	—	—	—	—	15	3	
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	—	—	1	4	5	4	4	—	—	—	1	4	1	—	—	—	—	2	1	2	1	1	—	—	32	4	
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	76	107	206	178	284	331	278	7	6	8	5	25	6	11	3	5	9	2	14	4	10	12	1	—	1,588	3	
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
38	HV	Distribution Line	SWER conductor	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	—	—	—	—	6	13	69	20	21	30	46	34	24	60	36	15	19	12	11	7	27	34	11	—	495	3	
40	HV	Distribution Cable	Distribution UG PILC	km	—	—	—	—	—	28	41	6	7	11	5	9	8	14	4	5	7	1	1	1	—	—	—	—	148	3	
41	HV	Distribution Cable	Distribution Submarine Cable	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	—	—	—	—	—	1	3	—	—	—	—	4	3	1	1	5	6	4	—	—	2	—	—	—	30	4	
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	2	—	2	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	14	43	149	243	477	900	140	144	140	174	127	120	131	136	143	127	195	129	94	98	117	25	—	3,867	3	
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	—	—	—	—	—	10	112	24	17	29	19	39	33	49	33	28	38	3	27	8	18	9	13	—	509	3	
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	—	—	—	—	3	9	45	7	14	28	10	15	10	10	17	11	10	8	13	6	6	7	3	—	232	3	
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	1	12	34	125	242	387	717	78	85	91	82	54	48	49	63	62	36	48	48	58	53	52	14	—	2,439	3	
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	—	—	—	—	16	50	197	80	85	108	126	170	124	158	131	111	67	57	49	48	79	84	15	—	1,755	3	
49	HV	Distribution Transformer	Voltage regulators	No.	—	—	—	—	2	—	—	—	—	—	2	3	3	2	4	5	3	—	—	2	2	3	—	—	29	3	
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	—	—	—	—	16	50	197	80	85	108	126	170	124	158	131	111	67	57	49	48	79	84	15	—	1,755	3	
51	LV	LV Line	LV OH Conductor	km	4	17	40	72	43	21	22	1	—	1	—	1	—	1	—	1	1	—	—	—	—	—	1	—	—	226	3
52	LV	LV Cable	LV UG Cable	km	—	—	—	—	1	137	120	18	18	31	39	46	31	36	36	26	19	9	13	10	11	17	2	—	620	3	
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	—	0	0	0	1	17	12	2	1	2	4	3	3	4	4	2	3	2	2	2	2	1	—	—	69	3	
54	LV	Connections	OH/UG consumer service connections	No.	—	—	—	6	6	5	17,848	704	904	1,051	1,036	1,136	1,181	1,050	1,140	924	668	647	527	767	586	760	173	—	31,119	3	
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	—	—	8	9	3	16	29	—	—	13	9	8	2	10	5	6	12	5	12	4	12	2	8	—	173	3	
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	—	—	—	—	—	—	—	—	4	10	4	8	1	4	1	5	8	2	5	3	2	—	1	—	58	4	
57	All	Capacitor Banks	Capacitors including controls	No.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A
58	All	Load Control	Centralised plant	Lot	—	—	—	—	—	1	—	—	—	—	—	—	—	—	—	—	—	1	—	1	—	—	—	—	—	3	4
59	All	Load Control	Relays	No.	—	—	—	4	19	54	179	37	38	47	84	141	99	126	94	47	38	18	15	16	17	6	1	—	1,080	3	
60	All	Civils	Cable Tunnels	km	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	N/A

Company Name	<b>Aurora Energy Limited</b>
For Year Ended	<b>31 March 2015</b>
Network / Sub-network Name	<b>Total Business</b>

**SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES**

This schedule requires a summary of the key characteristics of the overhead line and underground cable network. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

9			
10	<b>Circuit length by operating voltage (at year end)</b>	<b>Overhead (km)</b>	<b>Underground (km)</b>
11	> 66kV	—	—
12	50kV & 66kV	108	1
13	33kV	405	91
14	SWER (all SWER voltages)	9	—
15	22kV (other than SWER)	—	—
16	6.6kV to 11kV (inclusive—other than SWER)	2,319	956
17	Low voltage (< 1kV)	1,050	877
18	<b>Total circuit length (for supply)</b>	<b>3,890</b>	<b>1,925</b>
19			
20	Dedicated street lighting circuit length (km)	46	174
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)		
22			
23	<b>Overhead circuit length by terrain (at year end)</b>	<b>Circuit length (km)</b>	<b>(% of total overhead length)</b>
24	Urban	1,172	30%
25	Rural	2,615	67%
26	Remote only	—	—
27	Rugged only	103	3%
28	Remote and rugged	—	—
29	Unallocated overhead lines	—	—
30	<b>Total overhead length</b>	<b>3,890</b>	<b>100%</b>
31			
32		<b>Circuit length (km)</b>	<b>(% of total circuit length)</b>
33	Length of circuit within 10km of coastline or geothermal areas (where known)	2,125	37%
34		<b>Circuit length (km)</b>	<b>(% of total overhead length)</b>
35	Overhead circuit requiring vegetation management	213	5%

Company Name	<b>Aurora Energy Limited</b>
For Year Ended	<b>31 March 2015</b>
Network / Sub-network Name	<b>Dunedin</b>

**SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES**

This schedule requires a summary of the key characteristics of the overhead line and underground cable network. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

9			
10	<b>Circuit length by operating voltage (at year end)</b>	<b>Overhead (km)</b>	<b>Underground (km)</b>
11	> 66kV	—	—
12	50kV & 66kV	—	—
13	33kV	144	76
14	SWER (all SWER voltages)	9	—
15	22kV (other than SWER)	—	—
16	6.6kV to 11kV (inclusive—other than SWER)	731	312
17	Low voltage (< 1kV)	824	251
18	<b>Total circuit length (for supply)</b>	<b>1,707</b>	<b>639</b>
19			
20	Dedicated street lighting circuit length (km)	43	107
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)		
22			
23	<b>Overhead circuit length by terrain (at year end)</b>	<b>Circuit length (km)</b>	<b>(% of total overhead length)</b>
24	Urban	973	57%
25	Rural	721	42%
26	Remote only	—	—
27	Rugged only	14	1%
28	Remote and rugged	—	—
29	Unallocated overhead lines	—	—
30	<b>Total overhead length</b>	<b>1,707</b>	<b>100%</b>
31			
32		<b>Circuit length (km)</b>	<b>(% of total circuit length)</b>
33	Length of circuit within 10km of coastline or geothermal areas (where known)	2,125	91%
34		<b>Circuit length (km)</b>	<b>(% of total overhead length)</b>
35	Overhead circuit requiring vegetation management	96	6%

Company Name	<b>Aurora Energy Limited</b>
For Year Ended	<b>31 March 2015</b>
Network / Sub-network Name	<b>Central Otago</b>

**SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES**

This schedule requires a summary of the key characteristics of the overhead line and underground cable network. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

9			
10	<b>Circuit length by operating voltage (at year end)</b>	<b>Overhead (km)</b>	<b>Underground (km)</b>
11	> 66kV	–	–
12	50kV & 66kV	108	1
13	33kV	261	14
14	SWER (all SWER voltages)	–	–
15	22kV (other than SWER)	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	1,588	642
17	Low voltage (< 1kV)	226	620
18	<b>Total circuit length (for supply)</b>	<b>2,183</b>	<b>1,278</b>
19			
20	Dedicated street lighting circuit length (km)	3	66
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)		
22			
23	<b>Overhead circuit length by terrain (at year end)</b>	<b>Circuit length (km)</b>	<b>(% of total overhead length)</b>
24	Urban	199	9%
25	Rural	1,895	87%
26	Remote only	–	–
27	Rugged only	89	4%
28	Remote and rugged	–	–
29	Unallocated overhead lines	–	–
30	<b>Total overhead length</b>	<b>2,183</b>	<b>100%</b>
31			
32		<b>Circuit length (km)</b>	<b>(% of total circuit length)</b>
33	Length of circuit within 10km of coastline or geothermal areas (where known)	–	–
34		<b>Circuit length (km)</b>	<b>(% of total overhead length)</b>
35	Overhead circuit requiring vegetation management	116	5%

Company Name

Aurora Energy Limited

For Year Ended

31 March 2015

**SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS**

This schedule requires information concerning embedded networks owned by an EDB that are embedded in another EDB's network or in another embedded network.

sch ref

	Location *	Number of ICPs served	Line charge revenue (\$000)
8			
9	Heritage Estate (Te Anau)	99	69
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26	* Extend embedded distribution networks table as necessary to disclose each embedded network owned by the EDB which is embedded in another EDB's network or in another embedded network		

Company Name **Aurora Energy Limited**For Year Ended **31 March 2015**Network / Sub-network Name **Total Business****SCHEDULE 9e: REPORT ON NETWORK DEMAND**

This schedule requires a summary of the key measures of network utilisation for the disclosure year (number of new connections including distributed generation, peak demand and electricity volumes conveyed).

sch ref

**9e(i): Consumer Connections**

Number of ICPs connected in year by consumer type

Consumer types defined by EDB\*

Standard Domestic

Load Group 0

Load Group 0A

Load Group 1A

Load Group 1

Load Group 2

Load Group 3

Load Group 3A

Load Group 4

Load Group 5

Street Lighting

\* include additional rows if needed

Connections total

Number of  
connections (ICPs)

878

(10)

52

16

126

104

2

6

7

(1)

2

1,182

**Distributed generation**

Number of connections made in year

144

connections

Capacity of distributed generation installed in year

0.56

MVA

**9e(ii): System Demand****Maximum coincident system demand**

GXP demand

225

plus Distributed generation output at HV and above

61

**Maximum coincident system demand**

286

less Net transfers to (from) other EDBs at HV and above

(0)

**Demand on system for supply to consumers' connection points**

286

Demand at time  
of maximum  
coincident  
demand (MW)**Electricity volumes carried**

Electricity supplied from GXPs

1,069

less Electricity exports to GXPs

47

plus Electricity supplied from distributed generation

324

less Net electricity supplied to (from) other EDBs

(1)

**Electricity entering system for supply to consumers' connection points**

1,347

less Total energy delivered to ICPs

1,248

**Electricity losses (loss ratio)**

99

7.3%

**Load factor**

0.54

**9e(iii): Transformer Capacity**

(MVA)

Distribution transformer capacity (EDB owned)

854

Distribution transformer capacity (Non-EDB owned, estimated)

74

**Total distribution transformer capacity**

928

**Zone substation transformer capacity**

902

Company Name **Aurora Energy Limited**For Year Ended **31 March 2015**Network / Sub-network Name **Dunedin****SCHEDULE 9e: REPORT ON NETWORK DEMAND**

This schedule requires a summary of the key measures of network utilisation for the disclosure year (number of new connections including distributed generation, peak demand and electricity volumes conveyed).

sch ref

**9e(i): Consumer Connections**

Number of ICPs connected in year by consumer type

Consumer types defined by EDB\*

Standard Domestic

Load Group 0

Load Group 0A

Load Group 1A

Load Group 1

Load Group 2

Load Group 3

Load Group 3A

Load Group 4

Load Group 5

Street Lighting

\* include additional rows if needed

Connections total

Number of  
connections (ICPs)

283

(16)

(3)

6

110

24

(2)

-

1

(1)

2

404

**Distributed generation**

Number of connections made in year

55

connections

Capacity of distributed generation installed in year

0.20

MVA

**9e(ii): System Demand****Maximum coincident system demand**

GXP demand

147

plus Distributed generation output at HV and above

48

**Maximum coincident system demand**

195

less Net transfers to (from) other EDBs at HV and above

-

**Demand on system for supply to consumers' connection points**

195

**Electricity volumes carried**

Electricity supplied from GXPs

713

less Electricity exports to GXPs

3

plus Electricity supplied from distributed generation

152

less Net electricity supplied to (from) other EDBs

-

**Electricity entering system for supply to consumers' connection points**

862

less Total energy delivered to ICPs

1,248

**Electricity losses (loss ratio)**

(386)

(44.9%)

**Load factor**

0.51

**9e(iii): Transformer Capacity**

Distribution transformer capacity (EDB owned)

482

Distribution transformer capacity (Non-EDB owned, estimated)

49

**Total distribution transformer capacity**

530

**Zone substation transformer capacity**

610

Company Name **Aurora Energy Limited**For Year Ended **31 March 2015**Network / Sub-network Name **Central Otago****SCHEDULE 9e: REPORT ON NETWORK DEMAND**

This schedule requires a summary of the key measures of network utilisation for the disclosure year (number of new connections including distributed generation, peak demand and electricity volumes conveyed).

sch ref

**9e(i): Consumer Connections**

Number of ICPs connected in year by consumer type

Consumer types defined by EDB\*

Standard Domestic

Load Group 0

Load Group 0A

Load Group 1A

Load Group 1

Load Group 2

Load Group 3

Load Group 3A

Load Group 4

Load Group 5

Street Lighting

\* include additional rows if needed

Connections total

Number of  
connections (ICPs)

591

6

55

10

16

79

4

6

6

-

-

773

**Distributed generation**

Number of connections made in year

89

connections

Capacity of distributed generation installed in year

0.36

MVA

**9e(ii): System Demand****Maximum coincident system demand**

GXP demand

78

plus Distributed generation output at HV and above

24

**Maximum coincident system demand**

102

less Net transfers to (from) other EDBs at HV and above

-

**Demand on system for supply to consumers' connection points**

102

**Electricity volumes carried**

Electricity supplied from GXPs

357

less Electricity exports to GXPs

44

plus Electricity supplied from distributed generation

172

less Net electricity supplied to (from) other EDBs

-

**Electricity entering system for supply to consumers' connection points**

485

less Total energy delivered to ICPs

1,248

**Electricity losses (loss ratio)**

(763)

(157.4%)

**Load factor**

0.54

**9e(iii): Transformer Capacity**

Distribution transformer capacity (EDB owned)

371

Distribution transformer capacity (Non-EDB owned, estimated)

25

**Total distribution transformer capacity**

396

**Zone substation transformer capacity**

292



Company Name **Aurora Energy Limited**For Year Ended **31 March 2015**Network / Sub-network Name **Total Business****SCHEDULE 10: REPORT ON NETWORK RELIABILITY**

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

**10(i): Interruptions****Interruptions by class**

Class A (planned interruptions by Transpower)  
 Class B (planned interruptions on the network)  
 Class C (unplanned interruptions on the network)  
 Class D (unplanned interruptions by Transpower)  
 Class E (unplanned interruptions of EDB owned generation)  
 Class F (unplanned interruptions of generation owned by others)  
 Class G (unplanned interruptions caused by another disclosing entity)  
 Class H (planned interruptions caused by another disclosing entity)  
 Class I (interruptions caused by parties not included above)

**Total****Number of interruptions**

317
488
805

**Interruption restoration**

Class C interruptions restored within

**≤3Hrs****>3hrs**

360	128
-----	-----

**SAIFI and SAIDI by class**

Class A (planned interruptions by Transpower)  
 Class B (planned interruptions on the network)  
 Class C (unplanned interruptions on the network)  
 Class D (unplanned interruptions by Transpower)  
 Class E (unplanned interruptions of EDB owned generation)  
 Class F (unplanned interruptions of generation owned by others)  
 Class G (unplanned interruptions caused by another disclosing entity)  
 Class H (planned interruptions caused by another disclosing entity)  
 Class I (interruptions caused by parties not included above)

**Total****SAIFI****SAIDI**

0.12	24.3
1.25	105.7
1.37	130.0

**Normalised SAIFI and SAIDI**

Classes B &amp; C (interruptions on the network)

**Normalised SAIFI****Normalised SAIDI**

1.37	123.6
------	-------

**Quality path normalised reliability limit**

SAIFI and SAIDI limits applicable to disclosure year\*

\* not applicable to exempt EDBs

**SAIFI reliability limit****SAIDI reliability limit**

1.67	98.3
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Company Name **Aurora Energy Limited**For Year Ended **31 March 2015**Network / Sub-network Name **Total Business****SCHEDULE 10: REPORT ON NETWORK RELIABILITY**

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

**10(ii): Class C Interruptions and Duration by Cause****Cause**

Lightning  
Vegetation  
Adverse weather  
Adverse environment  
Third party interference  
Wildlife  
Human error  
Defective equipment  
Cause unknown

**SAIFI****SAIDI**

0.02	0.5
0.25	33.3
0.18	17.0
0.01	0.6
0.08	6.3
0.06	3.9
0.06	1.0
0.29	29.3
0.28	13.5

**10(iii): Class B Interruptions and Duration by Main Equipment Involved****Main equipment involved**

Subtransmission lines  
Subtransmission cables  
Subtransmission other  
Distribution lines (excluding LV)  
Distribution cables (excluding LV)  
Distribution other (excluding LV)

**SAIFI****SAIDI**

0.00	0.2
–	–
–	–
0.09	19.0
0.01	1.3
0.02	3.7

**10(iv): Class C Interruptions and Duration by Main Equipment Involved****Main equipment involved**

Subtransmission lines  
Subtransmission cables  
Subtransmission other  
Distribution lines (excluding LV)  
Distribution cables (excluding LV)  
Distribution other (excluding LV)

**SAIFI****SAIDI**

0.09	2.5
–	–
0.01	0.3
0.95	87.8
0.10	6.6
0.10	8.5

**10(v): Fault Rate****Main equipment involved**

Subtransmission lines  
Subtransmission cables  
Subtransmission other  
Distribution lines (excluding LV)  
Distribution cables (excluding LV)  
Distribution other (excluding LV)

**Number of Faults****Circuit length (km)****Fault rate (faults per 100km)**

27	513
–	92
3	
349	2,328
19	956
178	
576	

5.26
–
14.99
1.99

**Total**

Company Name	<b>Aurora Energy Limited</b>
For Year Ended	<b>31 March 2015</b>
Network / Sub-network Name	<b>Dunedin</b>

**SCHEDULE 10: REPORT ON NETWORK RELIABILITY**

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8	<b>10(i): Interruptions</b>		
9	<b>Interruptions by class</b>	<b>Number of interruptions</b>	
10	Class A (planned interruptions by Transpower)		
11	Class B (planned interruptions on the network)	62	
12	Class C (unplanned interruptions on the network)	154	
13	Class D (unplanned interruptions by Transpower)		
14	Class E (unplanned interruptions of EDB owned generation)		
15	Class F (unplanned interruptions of generation owned by others)		
16	Class G (unplanned interruptions caused by another disclosing entity)		
17	Class H (planned interruptions caused by another disclosing entity)		
18	Class I (interruptions caused by parties not included above)		
19	<b>Total</b>	216	
20			
21	<b>Interruption restoration</b>	<b>≤3Hrs</b>	<b>&gt;3hrs</b>
22	Class C interruptions restored within	92	62
23			
24	<b>SAIFI and SAIDI by class</b>	<b>SAIFI</b>	<b>SAIDI</b>
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.04	6.9
27	Class C (unplanned interruptions on the network)	0.73	74.1
28	Class D (unplanned interruptions by Transpower)		
29	Class E (unplanned interruptions of EDB owned generation)		
30	Class F (unplanned interruptions of generation owned by others)		
31	Class G (unplanned interruptions caused by another disclosing entity)		
32	Class H (planned interruptions caused by another disclosing entity)		
33	Class I (interruptions caused by parties not included above)		
34	<b>Total</b>	0.77	81.0
35			
36	<b>Normalised SAIFI and SAIDI</b>	<b>Normalised SAIFI</b>	<b>Normalised SAIDI</b>
37	Classes B & C (interruptions on the network)	0.77	67.9
38			
39	<b>Quality path normalised reliability limit</b>	<b>SAIFI reliability limit</b>	<b>SAIDI reliability limit</b>
40	SAIFI and SAIDI limits applicable to disclosure year*	0.89	49.2
41	* not applicable to exempt EDBs		

Company Name **Aurora Energy Limited**For Year Ended **31 March 2015**Network / Sub-network Name **Dunedin****SCHEDULE 10: REPORT ON NETWORK RELIABILITY**

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

**10(ii): Class C Interruptions and Duration by Cause****Cause**

Lightning  
Vegetation  
Adverse weather  
Adverse environment  
Third party interference  
Wildlife  
Human error  
Defective equipment  
Cause unknown

**SAIFI****SAIDI**

0.01	0.5
0.19	32.8
0.16	14.8
0.00	0.0
0.06	6.5
0.03	1.7
0.01	0.0
0.23	14.3
0.04	3.3

**10(iii): Class B Interruptions and Duration by Main Equipment Involved****Main equipment involved**

Subtransmission lines  
Subtransmission cables  
Subtransmission other  
Distribution lines (excluding LV)  
Distribution cables (excluding LV)  
Distribution other (excluding LV)

**SAIFI****SAIDI**

—	—
—	—
—	—
0.03	3.4
0.00	0.0
0.01	3.5

**10(iv): Class C Interruptions and Duration by Main Equipment Involved****Main equipment involved**

Subtransmission lines  
Subtransmission cables  
Subtransmission other  
Distribution lines (excluding LV)  
Distribution cables (excluding LV)  
Distribution other (excluding LV)

**SAIFI****SAIDI**

—	—
—	—
—	—
0.58	66.4
0.10	4.9
0.06	2.8

**10(v): Fault Rate****Main equipment involved**

Subtransmission lines  
Subtransmission cables  
Subtransmission other  
Distribution lines (excluding LV)  
Distribution cables (excluding LV)  
Distribution other (excluding LV)

**Number of Faults****Circuit length (km)****Fault rate (faults per 100km)**

5	144
—	76
—	—
93	731
12	312
59	—
169	—

3.47
—
12.72
3.85

**Total**

Company Name **Aurora Energy Limited**For Year Ended **31 March 2015**Network / Sub-network Name **Central Otago****SCHEDULE 10: REPORT ON NETWORK RELIABILITY**

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

**10(i): Interruptions****Interruptions by class**

Class A (planned interruptions by Transpower)  
 Class B (planned interruptions on the network)  
 Class C (unplanned interruptions on the network)  
 Class D (unplanned interruptions by Transpower)  
 Class E (unplanned interruptions of EDB owned generation)  
 Class F (unplanned interruptions of generation owned by others)  
 Class G (unplanned interruptions caused by another disclosing entity)  
 Class H (planned interruptions caused by another disclosing entity)  
 Class I (interruptions caused by parties not included above)

**Total****Number of interruptions**

255
334
589

**Interruption restoration**

Class C interruptions restored within

**≤3Hrs****>3hrs**

268	66
-----	----

**SAIFI and SAIDI by class**

Class A (planned interruptions by Transpower)  
 Class B (planned interruptions on the network)  
 Class C (unplanned interruptions on the network)  
 Class D (unplanned interruptions by Transpower)  
 Class E (unplanned interruptions of EDB owned generation)  
 Class F (unplanned interruptions of generation owned by others)  
 Class G (unplanned interruptions caused by another disclosing entity)  
 Class H (planned interruptions caused by another disclosing entity)  
 Class I (interruptions caused by parties not included above)

**Total****SAIFI****SAIDI**

0.27	55.3
2.16	162.1
2.43	217.4

**Normalised SAIFI and SAIDI**

Classes B &amp; C (interruptions on the network)

**Normalised SAIFI****Normalised SAIDI**

2.43	217.4
------	-------

**Quality path normalised reliability limit**

SAIFI and SAIDI limits applicable to disclosure year\*

\* not applicable to exempt EDBs

**SAIFI reliability limit****SAIDI reliability limit**

3.68	218.3
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Company Name **Aurora Energy Limited**For Year Ended **31 March 2015**Network / Sub-network Name **Central Otago****SCHEDULE 10: REPORT ON NETWORK RELIABILITY**

This schedule requires a summary of the key measures of network reliability (interruptions, SAIDI, SAIFI and fault rate) for the disclosure year. EDBs must provide explanatory comment on their network reliability for the disclosure year in Schedule 14 (Explanatory notes to templates). The SAIFI and SAIDI information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

**10(ii): Class C Interruptions and Duration by Cause****Cause**

Lightning  
Vegetation  
Adverse weather  
Adverse environment  
Third party interference  
Wildlife  
Human error  
Defective equipment  
Cause unknown

**SAIFI****SAIDI**

0.04	0.5
0.37	34.3
0.23	21.0
0.02	1.6
0.10	6.0
0.11	7.8
0.15	2.6
0.42	55.8
0.70	31.6

**10(iii): Class B Interruptions and Duration by Main Equipment Involved****Main equipment involved**

Subtransmission lines  
Subtransmission cables  
Subtransmission other  
Distribution lines (excluding LV)  
Distribution cables (excluding LV)  
Distribution other (excluding LV)

**SAIFI****SAIDI**

0.01	0.7
–	–
–	–
0.21	46.9
0.02	3.6
0.03	4.1

**10(iv): Class C Interruptions and Duration by Main Equipment Involved****Main equipment involved**

Subtransmission lines  
Subtransmission cables  
Subtransmission other  
Distribution lines (excluding LV)  
Distribution cables (excluding LV)  
Distribution other (excluding LV)

**SAIFI****SAIDI**

0.24	6.8
–	–
0.02	0.8
1.62	126.1
0.10	9.6
0.17	18.8

**10(v): Fault Rate****Main equipment involved**

Subtransmission lines  
Subtransmission cables  
Subtransmission other  
Distribution lines (excluding LV)  
Distribution cables (excluding LV)  
Distribution other (excluding LV)

**Number of Faults****Circuit length (km)****Fault rate (faults per 100km)**

22	369
–	15
3	
256	1,588
7	642
119	
407	

5.96
–
16.12
1.09

**Total**

Company Name	Aurora Energy Limited
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For Year Ended	31 March 2015
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## Schedule 14      Mandatory Explanatory Notes

*(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)*

1. This Schedule requires EDBs to provide explanatory notes to information provided in accordance with clauses 2.3.1, 2.4.21, 2.4.22, and 2.5.2.
2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 12 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.
3. Schedule 15 (Voluntary Explanatory Notes to Schedules) provides for EDBs to give additional explanation of disclosed information should they elect to do so.

### *Return on Investment (Schedule 2)*

4. In the box below, comment on return on investment as disclosed in Schedule 2. This comment must include information on reclassified items in accordance with clause 2.7.1(2).

**Box 1: Explanatory comment on return on investment**

The 2015 ROI is below the 25<sup>th</sup> percentile estimate of WACC. There have been no items reclassified in accordance with clause 2.7.1(2)

### *Regulatory Profit (Schedule 3)*

5. In the box below, comment on regulatory profit for the disclosure year as disclosed in Schedule 3. This comment must include-
  - 5.1 a description of material items included in 'other regulatory line income' other than gains and losses on asset sales, as disclosed in 3(i) of Schedule 3
  - 5.2 information on reclassified items in accordance with clause 2.7.1(2).

**Box 2: Explanatory comment on regulatory profit**

Included in 'other regulatory line income' are the following (all figures in \$000's):

- Transmission Rental Rebate Received \$ 875
- Transmission Charge Recovered \$ 1,361
- Other income incl accident damage \$ 397

There have been no items reclassified in accordance with clause 2.7.1(2)

*Merger and acquisition expenses (3(iv) of Schedule 3)*

6. If the EDB incurred merger and acquisitions expenditure during the disclosure year, provide the following information in the box below-

6.1 information on reclassified items in accordance with clause 2.7.1(2)

6.2 any other commentary on the benefits of the merger and acquisition expenditure to the EDB.

**Box 3: Explanatory comment on merger and acquisition expenditure**

There were no merger and acquisition costs incurred.

*Value of the Regulatory Asset Base (Schedule 4)*

7. In the box below, comment on the value of the regulatory asset base (rolled forward) in Schedule 4. This comment must include information on reclassified items in accordance with clause 2.7.1(2).



**Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)**

The amounts disclosed in the regulatory asset base calculations as assets commissioned have been reduced by the amount of customer contributions received and have been adjusted in respect of acquisitions sourced from Delta Utility Services Ltd (a related party).

In respect of the 2015 disclosure year, related party transactions have been recorded either at :

- Directly attributable cost incurred by Delta or
- At valuation – in accordance with an independent valuation process undertaken in respect of specific larger projects

The impact of these adjustments are as follows (\$000):

	2015 Yr
Original Cost (and regulatory tax value)	24,102
Less offset customer contributions	(4,435)
Less margin/ indirect cost on related party capex	(3,973)
Less original cost of assets subject to valuation	(8,121)
Plus assets included at valuation	9,725
	-----
Value RAB assets commissioned	17,298

There have been no items reclassified in accordance with clause 2.7.1(2)

*Regulatory tax allowance: disclosure of permanent differences (5a(i) of Schedule 5a)*

8. In the box below, provide descriptions and workings of the following items, as recorded in the asterisked categories in 5a(i) of Schedule 5a-

- 8.1 income not included in regulatory profit / (loss) before tax but taxable;
- 8.2 expenditure or loss in regulatory profit / (loss) before tax but not deductible;
- 8.3 income included in regulatory profit / (loss) before tax but not taxable;
- 8.4 expenditure or loss deductible but not in regulatory profit / (loss) before tax.

**Box 5: Regulatory tax allowance: permanent differences**

The figure shown in 'Income not included in regulatory profit / (loss) before tax but taxable' is an adjustment in respect of \$1,957,000 of customer contribution that is assessable for income tax purposes in that year.

The figure 'Expenditure or loss in regulatory profit or (loss) before tax but not deductible' relates to (\$19,000) being the movement in doubtful debts.

*Regulatory tax allowance: disclosure of temporary differences (5a(vi) of Schedule 5a)*

9. In the box below, provide descriptions and workings of items recorded in the asterisked category 'Tax effect of other temporary differences' in 5a(vi) of Schedule 5a.

**Box 6: Temporary differences / Tax effect of other temporary differences (current disclosure year)**

The \$553,000 shown in the line 'Tax effect of other temporary differences' is (in \$000):

Value of customer contributions as above	\$1,957
Plus doubtful debts as above	\$19
	-----
Sub-total of differences	\$1,976
Tax effect at 28%	\$553

*Related party transactions: disclosure of related party transactions (Schedule 5b)*

10. In the box below, provide descriptions of related party transactions beyond those disclosed on schedule 5b including identification and descriptions as to the nature of directly attributable costs disclosed under clause 2.3.6(1)(b).

**Box 7: Related party transactions**

Over 50% of sales of goods and service by Aurora's sibling company, Delta Utility Services Limited, are to third parties and third parties may purchase the same or similar goods and services provided to Aurora on substantially the same terms and conditions, including price

Accordingly, related party transactions disclosed in schedule 5b are valued in accordance with clause 2.3.6(1)(c).

*Cost allocation (Schedule 5d)*

11. In the box below, comment on cost allocation as disclosed in Schedule 5d. This comment must include information on reclassified items in accordance with clause 2.7.1(2).

**Box 8: Cost allocation**

Operating costs along with pass through and recoverable costs are all directly attributable to the regulated business.

Operating costs include the overhead component of related party capex expenditure.

There have been no items reclassified in accordance with clause 2.7.1(2).

*Asset allocation (Schedule 5e)*

12. In the box below, comment on asset allocation as disclosed in Schedule 5e. This comment must include information on reclassified items in accordance with clause 2.7.1(2).

**Box 9: Commentary on asset allocation**

All assets acquired are all directly attributable to the regulated business.

There have been no items reclassified in accordance with clause 2.7.1(2).

*Capital Expenditure for the Disclosure Year (Schedule 6a)*

13. In the box below, comment on capital expenditure for the disclosure year, as disclosed in Schedule 6a. This comment must include-
- 13.1 a description of the materiality threshold applied to identify material projects and programmes described in Schedule 6a;
  - 13.2 information on reclassified items in accordance with clause 2.7.1(2),

**Box 10: Explanation of capital expenditure for the disclosure year**

Consumer connection capital expenditure disclosed in 6a(iii) is all connections. Insufficient data is currently captured to align that expenditure with consumer load groups.

The listed projects are the higher value projects included within the specific reporting categories of 'asset relocations', 'quality of supply', 'other reliability, safety and environment'.

There have been no items reclassified in accordance with clause 2.7.1(2).

*Operational Expenditure for the Disclosure Year (Schedule 6b)*

14. In the box below, comment on operational expenditure for the disclosure year, as disclosed in Schedule 6b. This comment must include-
  - 14.1 commentary on assets replaced or renewed with asset replacement and renewal operating expenditure, as reported in 6b(i) of Schedule 6b;
  - 14.2 information on reclassified items in accordance with clause 2.7.1(2);
  - 14.3 commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, a including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

**Box 11: Explanation of operational expenditure for the disclosure year**

[Insert text here]

Expenditure on asset replacement and renewal is relatively minor in nature, generally, applying to asset components and designed to ensure the asset achieves its service life. Typically, such expenditure includes replacement and/or renewal of insulators, fuse links, service and link pillar components, cable terminations, equipment earth grids, transformer and switchgear components, including painting.

There have been no items reclassified in accordance with clause 2.7.1(2).

There are no items of operational expenditure that have been identified as atypical; however expenditure on vegetation management and routine and corrective maintenance have remained at higher levels than in disclosure years 2013 and earlier.

*Variance between forecast and actual expenditure (Schedule 7)*

15. In the box below, comment on variance in actual to forecast expenditure for the disclosure year, as reported in Schedule 7. This comment must include information on reclassified items in accordance with clause 2.7.1(2).

**Box 12: Explanatory comment on variance in actual to forecast expenditure**

Capital expenditure on consumer connections reflects increased development activity, mainly within the Central Otago subnetwork. Subdivision project activity has been maintained at elevated levels, and irrigation development in the Upper Clutha and Manuherikia Valley has been significant.

The variance in 'system growth' is largely attributable to development of two new rural zone substations, and associated distribution circuit upgrades, required to support irrigation growth in the Upper Clutha area. While the Lindis Crossing substation was commissioned during the period, consenting issues meant that no work associated with the Camp Hill substation was able to commence during the disclosure year.

Asset relocation activity has been greater than expected, largely driven by relocation of assets to facilitate irrigation infrastructure, and to facilitate a large commercial development on the Frankton Flats. In general, 'Consumer connection', 'system growth' and 'asset relocation' expenditure is generally driven by external factors and less controllable than other categories.

'Asset replacement and renewal' expenditure is below forecast. While Aurora has maintained an increased focus on pole renewals throughout the period, the significant volumes of consumer driven expenditure has resulted in some workforce constraints. =

Overall maintenance expenditure lower than forecast for the disclosure period. Greater than expected faults expenditure was incurred, partly as a result of an extreme weather event in Dunedin. Vegetation management expenditure was lower than forecast, despite largely accomplishing the identified cutting programme.

*Information relating to revenue and quantities for the disclosure year*

16. In the box below provide-

- 16.1 a comparison of the target revenue disclosed before the start of the disclosure year, in accordance with clauses 2.4.1 and 2.4.3(3) to total billed line charge revenue for the disclosure year, as disclosed in Schedule 8; and
- 16.2 explanatory comment on reasons for any material differences between target revenue and total billed line charge revenue.

**Box 13: Explanatory comment relating to revenue for the disclosure year**

Total delivery revenue budgeted	\$89.870 million (2014 pricing methodology)
Reported – Schedule 8 (Total Business)	\$89.333 million
Difference	\$0.537 million below target

It is generally expected that total billed line charge revenue for an assessment period will be different from target revenue, due to variation in connection numbers and energy demand. Additionally, Aurora's prices are derived to ensure that allowable notional revenue, as determined under the default price path, is not exceeded.

In the assessment period, the volume of energy delivered to standard domestic consumers (the only consumer groups with volume-based pricing) increased modestly from the prior year (by 1.2%). Energy delivered to standard domestic consumers disclosed in 2013/14 was 565.3GWh, compared to 572.2GWh in this current disclosure (deliveries to standard domestic consumers remain well behind the 605.2GWh recorded in 2012/13).

Standard domestic connection numbers also increased by 1.2%. Standard domestic connection numbers disclosed in 2013/14 were 70,425, compared to 71,295 in this current disclosure.

Accordingly, there was a negligible difference in the average energy use per standard domestic consumer – 8025kWh versus 8,027kWh in 2013/14.

*Network Reliability for the Disclosure Year (Schedule 10)*

17. In the box below, comment on network reliability for the disclosure year, as disclosed in Schedule 10.

**Box 14: Commentary on network reliability for the disclosure year**

In accordance with Information Disclosure definitions:

- Overhead (subtransmission and distribution) includes poles, stay-wires, crossarms, braces, insulators, conductor (including droppers and connectors), binders and ties
- Underground (subtransmission and distribution) includes cable, mounting brackets, terminations and potheads.
- Other (subtransmission and distribution) includes HV fuses (including fuse operation), lighting arrestors, transformers, switchgear, switching and control errors.
- Faults include unplanned events <1 minute, and events not resulting in loss of supply to a consumer, which would otherwise be excluded from consideration as an interruption.

Specific commentary on matters relating to Aurora's reliability performance for the disclosure years is contained in 3.6 (p7) of Aurora's Annual Compliance Statement (2015), available from <http://www.auroraenergy.co.nz/content/thresholdcompliance.php>.

In accordance with issue 231 of the Issues Register for Electricity and Gas Information Disclosure, Aurora declares that it has derived specific SAIFI and SAIDI boundary values for each sub-network. These values have been derived from the same reference dataset used to develop the compliance attributed for the total business.

We have predominantly chosen to derive sub-network specific boundary values for internal management and reporting purposes.

*Insurance cover*

18. In the box below provide details of any insurance cover for the assets used to provide electricity distribution services, including-
  - 18.1 the EDB's approaches and practices in regard to the insurance of assets used to provide electricity distribution services, including the level of insurance;
  - 18.2 in respect of any self insurance, the level of reserves, details of how reserves are managed and invested, and details of any reinsurance.

**Box 15: Explanation of insurance cover**

Insurance cover has been obtained / in place with respect of zone substations, both for the buildings and the plant and equipment contained within them.

The material damage (including flood, earthquake etc.) cover for the zone substations and associated equipment is on a replacement cost basis.

Distribution assets including distribution substations, lines and cables etc. are not currently covered due to the geographical spread, the lower value of the individual assets and the reduced likelihood of significant loss on any less than region wide event. This notwithstanding, Aurora is currently evaluating a proposal to add cover to distribution substations.



Company Name Aurora Energy LimitedFor Year Ended 31 March 2015**Schedule 15 Voluntary Explanatory Notes**

*(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)*

1. This Schedule enable EDBs to provide, should they wish to-
  - 1.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.6.5;
  - 1.2 information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.
2. Information in this Schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.
3. Provide additional explanatory comment in the box below.

**Box 1: Voluntary explanatory comment on disclosed information**

There is a \$(\$1,497,000) discrepancy between the total line charge revenue reported in schedule 8, and that recorded in Aurora's financial system. The schedule 8 information has been compiled from a monthly reconciliation model using information derived from Aurora's connection management system. As such, the model may contain contain some wash-up values recorded in the disclosure period, but attributable to events outside the disclosure period. Line charge revenue derived from Aurora's financial system includes accruals for over/under reporting by retailers, calculated with respect to published loss ratios. The variability in retailer reporting can be significant month to month. The line charge revenue stated in schedule 3 (line 9) and schedule 7 (line 8) has been manually entered and reflects the value stated in Aurora's financial system.

## SCHEDULE 18

### Certification for Year-end Disclosures


#### Clause 2.9.2

We, Ian Murray Parton and David John Frow, being directors of Aurora Energy Ltd, certify that, having made all reasonable enquiry, to the best of our knowledge -

- a. the information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and
- b. the historical information used in the preparation of Schedules 8, 9a, 9b, 9c, 9d, 9e, 10, and 14 has been properly extracted from the Aurora Energy Limited accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained.



Ian Murray Parton



David John Frow

27 August 2015

## **Independent Auditor's Report**

### **To the Directors of Aurora Energy Limited and to the Commerce Commission**

The Auditor-General is the auditor of Aurora Energy Limited (the company). The Auditor-General has appointed me, Ian Lothian, using the staff and resources of Audit New Zealand, to provide an opinion, on her behalf, on whether Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the SAIDI and SAIFI information disclosed in Schedule 10 and the explanatory notes in boxes 1 to 12 in Schedule 14 ('the Disclosure Information') for the disclosure year ended [date], have been prepared, in all material respects, in accordance with the Electricity Distribution Disclosure Information Determination 2012 (the 'Determination').

### **Directors' responsibility for the Disclosure Information**

The directors of the company are responsible for preparation of the Disclosure Information in accordance with the Determination, and for such internal control as the directors determine is necessary to enable the preparation of the Disclosure Information that is free from material misstatement.

### **Auditor's responsibility for the Disclosure Information**

Our responsibility is to express an opinion on whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination.

### **Basis of opinion**

We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000: Assurance Engagements Other Than Audits or Reviews of Historical Financial Information issued by the External Reporting Board and the Standard on Assurance Engagements 3100: Compliance Engagements issued by the External Reporting Board.

These standards require that we comply with ethical requirements and plan and perform our audit to provide reasonable assurance (which is also referred to as 'audit' assurance) about whether the Disclosure Information has been prepared in all material respects in accordance with the Determination.

An audit involves performing procedures to obtain evidence about the amounts and disclosures in the Disclosure Information. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the Disclosure Information, whether due to fraud or error or non-compliance with the Determination. In making those risk assessments, the auditor considers internal control relevant to the company's preparation of the Disclosure Information 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 company's internal control.

An audit also involves evaluating:

- the appropriateness of assumptions used and whether they have been consistently applied; and
- the reasonableness of the significant judgements made by the directors of the company.

## **Use of this report**

This independent auditor's report has been prepared for the directors of the company and for the Commerce Commission for the purpose of providing those parties with independent audit assurance about whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the company or the Commerce Commission, or for any other purpose than that for which it was prepared.

## **Scope and inherent limitations**

Because of the inherent limitations of an audit engagement, and the test basis of the procedures performed, it is possible that fraud, error or non-compliance may occur and not be detected.

We did not examine every transaction, adjustment or event underlying the Disclosure Information nor do we guarantee complete accuracy of the Disclosure Information. Also we did not evaluate the security and controls over the electronic publication of the Disclosure Information.

The opinion expressed in this independent auditor's report has been formed on the above basis.

## **Independence**

When carrying out the engagement we followed the independence requirements of the Auditor-General, which incorporate the independence requirements of the External Reporting Board. We also complied with the independent auditor requirements specified in the Determination.

The Auditor-General, and her employees, and Audit New Zealand and its employees may deal with the company on normal terms within the ordinary course of trading activities of the company. Other than any dealings on normal terms within the ordinary course of business, this engagement and the annual audit of the company's financial statements, we have no relationship with or interests in the company.

## **Opinion**

In our opinion:

- As far as appears from an examination of them, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the company.

- The information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records and has been sourced, where appropriate, from the company's financial and non-financial systems.
- The company has complied with the Determination, in all material respects, in preparing the Disclosure Information.

In forming our opinion, we have obtained sufficient recorded evidence and all the information and explanations we have required.

A handwritten signature in black ink, reading "Ian Lothian". The signature is fluid and cursive, with the first name "Ian" and last name "Lothian" clearly distinguishable.

Ian Lothian  
Audit New Zealand  
On behalf of the Auditor-General  
Dunedin, New Zealand  
27 August 2015