



**EDB Information Disclosure Requirements
Information Templates
for
Schedules 1–10**

Company Name

[Nelson Electricity Ltd](#)

Disclosure Date

[22 August 2016](#)

Disclosure Year (year ended)

[31 March 2016](#)

Templates for Schedules 1–10 excluding 5f–5g
Template Version 4.1. Prepared 24 March 2015

Table of Contents

Schedule	Schedule name
1	ANALYTICAL RATIOS
2	REPORT ON RETURN ON INVESTMENT
3	REPORT ON REGULATORY PROFIT
4	REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)
5a	REPORT ON REGULATORY TAX ALLOWANCE
5b	REPORT ON RELATED PARTY TRANSACTIONS
5c	REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE
5d	REPORT ON COST ALLOCATIONS
5e	REPORT ON ASSET ALLOCATIONS
6a	REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR
6b	REPORT ON OPERATIONAL EXPENDITURE FOR THE DISCLOSURE YEAR
7	COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE
8	REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES
9a	ASSET REGISTER
9b	ASSET AGE PROFILE
9c	REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES
9d	REPORT ON EMBEDDED NETWORKS
9e	REPORT ON NETWORK DEMAND
10	REPORT ON NETWORK RELIABILITY

Disclosure Template Instructions

These templates have been prepared for use by EDBs when making disclosures under clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, and 2.5.2 of the Electricity Distribution Information Disclosure Determination 2012.

Company Name and Dates

To prepare the templates for disclosure, the supplier's company name should be entered in cell C8, the date of the last day of the current (disclosure) year should be entered in cell C12, and the date on which the information is disclosed should be entered in cell C10 of the CoverSheet worksheet.

The cell C12 entry (current year) is used to calculate disclosure years in the column headings that show above some of the tables and in labels adjacent to some entry cells. It is also used to calculate the 'For year ended' date in the template title blocks (the title blocks are the light green shaded areas at the top of each template).

The cell C8 entry (company name) is used in the template title blocks.

Dates should be entered in day/month/year order (Example -"1 April 2013").

Data Entry Cells and Calculated Cells

Data entered into this workbook may be entered only into the data entry cells. Data entry cells are the bordered, unshaded areas (white cells) in each template. Under no circumstances should data be entered into the workbook outside a data entry cell.

In some cases, where the information for disclosure is able to be ascertained from disclosures elsewhere in the workbook, such information is disclosed in a calculated cell.

Validation Settings on Data Entry Cells

To maintain a consistency of format and to help guard against errors in data entry, some data entry cells test keyboard entries for validity and accept only a limited range of values. For example, entries may be limited to a list of category names, to values between 0% and 100%, or either a numeric entry or the text entry "N/A". Where this occurs, a validation message will appear when data is being entered. These checks are applied to keyboard entries only and not, for example, to entries made using Excel's copy and paste facility.

Conditional Formatting Settings on Data Entry Cells

Schedule 2 cells G79 and I79:L79 will change colour if the total cashflows do not equal the corresponding values in table 2(ii).

Schedule 4 cells P99:P105 and P107 will change colour if the RAB values do not equal the corresponding values in table 4(ii).

Schedule 9b columns AA to AE (2013 to 2017) contain conditional formatting. The data entry cells for future years are hidden (are changed from white to yellow).

Schedule 9b cells AG10 to AG60 will change colour if the total assets at year end for each asset class does not equal the corresponding values in column I in Schedule 9a.

Schedule 9c cell G30 will change colour if G30 (overhead circuit length by terrain) does not equal G18 (overhead circuit length by operating voltage).

Inserting Additional Rows and Columns

The templates for schedules 4, 5b, 5c, 5d, 5e, 6a, 8, 9d, and 9e may require additional rows to be inserted in tables marked 'include additional rows if needed' or similar. Column A schedule references should not be entered in additional rows, and should be deleted from additional rows that are created by copying and pasting rows that have schedule references.

Additional rows in schedules 5c, 6a, and 9e must not be inserted directly above the first row or below the last row of a table. This is to ensure that entries made in the new row are included in the totals.

Schedules 5d and 5e may require new cost or asset category rows to be inserted in allocation change tables 5d(iii) and 5e(ii). Accordingly, cell protection has been removed from rows 77 and 78 of the respective templates to allow blocks of rows to be copied. The four steps to add new cost category rows to table 5d(iii) are: Select Excel rows 69:77, copy, select Excel row 78, insert copied cells. Similarly, for table 5e(ii): Select Excel rows 70:78, copy, select Excel row 79, then insert copied cells.

The template for schedule 8 may require additional columns to be inserted between column P and U. To avoid interfering with the title block entries, these should be inserted to the left of column S. If inserting additional columns, the formulas for standard consumers total, non-standard consumers totals and total for all consumers will need to be copied into the cells of the added columns. The formulas can be found in the equivalent cells of the existing columns.

Disclosures by Sub-Network

If the supplier has sub-networks, schedules 8, 9a, 9b, 9c, 9e, and 10 must be completed for the network and for each sub-network. A copy of the schedule worksheet(s) must be made for each sub-network and named accordingly.

Schedule References

The references labelled 'sch ref' in the leftmost column of each template are consistent with the row references in the Electricity Distribution ID Determination 2012 (as issued on 24 March 2015). They provide a common reference between the rows in the determination and the template.

Description of Calculation References

Calculation cell formulas contain links to other cells within the same template or elsewhere in the workbook. Key cell references are described in a column to the right of each template. These descriptions are provided to assist data entry. Cell references refer to the row of the template and not the schedule reference.

Worksheet Completion Sequence

Calculation cells may show an incorrect value until precedent cell entries have been completed. Data entry may be assisted by completing the schedules in the following order:

1. Coversheet
2. Schedules 5a–5e
3. Schedules 6a–6b
4. Schedule 8
5. Schedule 3
6. Schedule 4
7. Schedule 2
8. Schedule 7
9. Schedules 9a–9e
10. Schedule 10

Company Name **Nelson Electricity Ltd**
For Year Ended **31 March 2016**

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)
Operational expenditure	12,654	193	53,294	6,027	18,401
Network	2,916	44	12,280	1,389	4,240
Non-network	9,738	148	41,014	4,638	14,161
Expenditure on assets	3,433	52	14,460	1,635	4,992
Network	3,332	51	14,034	1,587	4,846
Non-network	101	2	425	48	147

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs (\$/GWh)	Revenue per average no. of ICPs (\$/ICP)
Total consumer line charge revenue	72,257	1,101
Standard consumer line charge revenue	74,886	1,066
Non-standard consumer line charge revenue	35,237	163,955

1(iii): Service intensity measures

Demand density	113	Maximum coincident system demand per km of circuit length (for supply) (kW/km)
Volume density	476	Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)
Connection point density	31	Average number of ICPs per km of circuit length (for supply) (ICPs/km)
Energy intensity	15,242	Total energy delivered to ICPs per average number of ICPs (kWh/ICP)

1(iv): Composition of regulatory income

	(\$000)	% of revenue
Operational expenditure	1,776	17.50%
Pass-through and recoverable costs excluding financial incentives and wash-ups	3,485	34.33%
Total depreciation	1,394	13.74%
Total revaluations	244	2.41%
Regulatory tax allowance	952	9.38%
Regulatory profit/(loss) including financial incentives and wash-ups	2,787	27.46%
Total regulatory income	10,149	

1(v): Reliability

Interruption rate	5.43	Interruptions per 100 circuit km
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Company Name

Nelson Electricity Ltd

For Year Ended

31 March 2016

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).

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

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

Mid-point estimate of post tax WACC

25th percentile estimate
75th percentile estimate

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

WACC rate used to set regulatory price path**Mid-point estimate of vanilla WACC**

25th percentile estimate
75th percentile estimate

CY-2	CY-1	Current Year CY
31 Mar 14	31 Mar 15	31 Mar 16
%	%	%

7.23%	5.43%	6.31%
7.23%	5.43%	6.31%
7.23%	5.43%	6.31%
5.43%	6.10%	5.37%
4.71%	5.39%	4.66%
6.14%	6.82%	6.09%

7.91%	6.21%	6.96%
7.91%	6.21%	6.96%
7.91%	6.21%	6.96%

8.77%	8.77%	7.19%
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6.11%	6.89%	6.02%
5.39%	6.17%	5.30%
6.83%	7.60%	6.74%

2(ii): Information Supporting the ROI

(\$'000)

Total opening RAB value
plus Opening deferred tax

Opening RIV**Line charge revenue**

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

Mid-year net cash outflows**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

Closing RIV**ROI – comparable to a vanilla WACC**

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

ROI – comparable to a post tax WACC

41,669	
(781)	
	40,888
	10,139
5,260	
581	
–	
689	
10	
	6,519
	–
41,100	
0	
–	
(1,044)	
	40,055

6.96%
44%
5.26%
28%
6.31%

Company Name

Nelson Electricity Ltd

For Year Ended

31 March 2016

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).

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

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						–
Total	–	–	–	–	–	–

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

6.77%

Year-end ROI – comparable to a post tax WACC

6.12%

* 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 **Nelson Electricity Ltd**
 For Year Ended **31 March 2016**

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

7	3(i): Regulatory Profit		(\$000)
8	Income		
9	Line charge revenue		10,139
10	plus Gains / (losses) on asset disposals		
11	plus Other regulated income (other than gains / (losses) on asset disposals)		10
12			
13	Total regulatory income		10,149
14	Expenses		
15	less Operational expenditure		1,776
16			
17	less Pass-through and recoverable costs excluding financial incentives and wash-ups		3,485
18			
19	Operating surplus / (deficit)		4,889
20			
21	less Total depreciation		1,394
22			
23	plus Total revaluations		244
24			
25	Regulatory profit / (loss) before tax		3,739
26			
27	less Term credit spread differential allowance		–
28			
29	less Regulatory tax allowance		952
30			
31	Regulatory profit/(loss) including financial incentives and wash-ups		2,787
32			
33	3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups		(\$000)
34	Pass through costs		
35	Rates		30
36	Commerce Act levies		17
37	Industry levies		52
38	CPP specified pass through costs		
39	Recoverable costs excluding financial incentives and wash-ups		
40	Electricity lines service charge payable to Transpower		3,262
41	Transpower new investment contract charges		124
42	System operator services		
43	Distributed generation allowance		
44	Extended reserves allowance		
45	Other recoverable costs excluding financial incentives and wash-ups		
46	Pass-through and recoverable costs excluding financial incentives and wash-ups		3,485
47			

Company Name **Nelson Electricity Ltd**
 For Year Ended **31 March 2016**

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

		(\$000)	
		CY-1 31 Mar 15	CY 31 Mar 16
48	3(iii): Incremental Rolling Incentive Scheme		
49			
50			
51	Allowed controllable opex		
52	Actual controllable opex		
53			
54	Incremental change in year		
55			
56			
57	CY-5 31 Mar 11		
58	CY-4 31 Mar 12		
59	CY-3 31 Mar 13		
60	CY-2 31 Mar 14		
61	CY-1 31 Mar 15		
62	Net incremental rolling incentive scheme		—
63			
64	Net recoverable costs allowed under incremental rolling incentive scheme		—
65	3(iv): Merger and Acquisition Expenditure		
70			(\$000)
66	Merger and acquisition expenditure		
67			
68	<i>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)</i>		
69	3(v): Other Disclosures		
70			(\$000)
71	Self-insurance allowance		

Company Name	Nelson Electricity Ltd
For Year Ended	31 March 2016

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(i): Regulatory Asset Base Value (Rolled Forward)

for year ended	RAB 31 Mar 12 (\$000)	RAB 31 Mar 13 (\$000)	RAB 31 Mar 14 (\$000)	RAB 31 Mar 15 (\$000)	RAB 31 Mar 16 (\$000)
Total opening RAB value	29,401	29,657	30,349	42,203	41,669
less Total depreciation	1,128	1,161	1,173	1,430	1,394
plus Total revaluations	462	255	465	35	244
plus Assets commissioned	922	1,598	12,561	1,093	581
less Asset disposals				232	—
plus Lost and found assets adjustment					—
plus Adjustment resulting from asset allocation					0
Total closing RAB value	29,657	30,349	42,203	41,669	41,100

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * (\$000)	RAB (\$000)
Total opening RAB value	41,669	41,669
less Total depreciation	1,394	1,394
plus Total revaluations	244	244
plus Assets commissioned (other than below)	581	581
Assets acquired from a regulated supplier		
Assets acquired from a related party		
Assets commissioned	581	581
less Asset disposals (other than below)		
Asset disposals to a regulated supplier		
Asset disposals to a related party		
Asset disposals	—	—
plus Lost and found assets adjustment		
plus Adjustment resulting from asset allocation		0
Total closing RAB value	41,100	41,100

* 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	Nelson Electricity Ltd
For Year Ended	31 March 2016

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

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

54	CPI ₄	1,200
55	CPI ₄ ⁻⁴	1,193
56	Revaluation rate (%)	0.59%

57

58

59

60

61

62

63

64

65

Unallocated RAB *		RAB	
(\$000)	(\$000)	(\$000)	(\$000)
41,669		41,669	
41,669		41,669	
	244		244

4(iv): Roll Forward of Works Under Construction

Unallocated works under construction		Allocated works under construction	
	132		132
455		455	
581		581	
	6		6

72

73

74

75

Highest rate of capitalised finance applied

Company Name	Nelson Electricity Ltd
For Year Ended	31 March 2016

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)	(\$000)
1,394		1,394	
	1,394		1,394

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
Total opening RAB value	99	5,632	10,161	521	15,917	3,394	2,254	3,420	270	41,669
less Total depreciation	2	154	243	26	610	129	113	92	27	1,394
plus Total revaluations	1	33	60	3	93	20	13	20	2	244
plus Assets commissioned	-	15	-	18	117	273	20	122	14	581
less Asset disposals	-	-	-	-	-	-	-	-	-	-
plus Lost and found assets adjustment	-	-	-	-	-	-	-	-	-	-
plus Adjustment resulting from asset allocation	-	-	-	-	-	-	-	-	-	-
plus Asset category transfers	-	-	-	-	-	-	-	-	-	-
Total closing RAB value	98	5,526	9,978	517	15,518	3,559	2,175	3,470	259	41,100
Asset Life										
Weighted average remaining asset life	-	37.0	30.2	26.6	24.4	24.7	15.4	23.3	1.1	(years)
Weighted average expected total asset life	60.0	50.4	44.3	57.7	54.5	54.8	39.9	44.8	7.5	(years)

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

S5a.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

5a(iv): Amortisation of Revaluations		(\$000)
Opening sum of RAB values without revaluations	39,623	
Adjusted depreciation	1,260	
Total depreciation	1,394	
Amortisation of revaluations		134

(\$000)

54	Opening tax losses		-	
55	plus	Current period tax losses	-	
56	less	Utilised tax losses	-	
57	Closing tax losses			-

(\$000)

60	Opening deferred tax		(781)
61			
62	<i>plus</i>	Tax effect of adjusted depreciation	353
63			
64	<i>less</i>	Tax effect of tax depreciation	425
65			
66	<i>plus</i>	Tax effect of other temporary differences*	3
67			
68	<i>less</i>	Tax effect of amortisation of initial differences in asset values	194
69			
70	<i>plus</i>	Deferred tax balance relating to assets acquired in the disclosure year	–
71			
72	<i>less</i>	Deferred tax balance relating to assets disposed in the disclosure year	–
73			
74	<i>plus</i>	Deferred tax cost allocation adjustment	(0)
75			
76	Closing deferred tax		(1,044)

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).

(\$000)

83	Opening sum of regulatory tax asset values		20,304	(€000)
84	<i>less</i>	Tax depreciation	1,518	
85	<i>plus</i>	Regulatory tax asset value of assets commissioned	579	
86	<i>less</i>	Regulatory tax asset value of asset disposals	–	
87	<i>plus</i>	Lost and found assets adjustment	–	
88	<i>plus</i>	Adjustment resulting from asset allocation	–	
89	<i>plus</i>	Other adjustments to the RAB tax value	–	
90	Closing sum of regulatory tax asset values		19,365	

Company Name **Nelson Electricity Ltd**
 For Year Ended **31 March 2016**

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	6
Operational expenditure	202
Capital expenditure	
Market value of asset disposals	
Other related party transactions	

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

Name of related party	Related party relationship
Network Tasman Limited	Shareholder (50%)
Marlborough Lines Limited	Shareholder (50%)

* 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
Network Tasman Limited	Opex	Business Support	49	ID clause 2.3.6(1)(d)
Marlborough Lines Limited	Opex	Business Support	102	ID clause 2.3.6(1)(d)
Network Tasman Limited	Opex	Fibre Optic Charges	9	ID clause 2.3.6(1)(a)
Network Tasman Limited	Sales	Lease of Building Space	6	ID clause 2.3.6(1)(a)
Marlborough Lines Limited	Opex	Directors Fees	20	ID clause 2.3.6(1)(a)
Network Tasman Limited	Opex	Directors Fees	20	ID clause 2.3.6(1)(a)
Network Tasman Limited	Opex	Administration Fee	2	ID clause 2.3.6(1)(d)
	[Select one]			[Select one]
	[Select one]			[Select one]
	[Select one]			[Select one]
	[Select one]			[Select one]
	[Select one]			[Select one]
	[Select one]			[Select one]
	[Select one]			[Select one]

* include additional rows if needed

Company Name **Nelson Electricity Ltd**
 For Year Ended **31 March 2016**

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

–

Company Name **Nelson Electricity Ltd**For Year Ended **31 March 2016****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

5d(i): Operating Cost Allocations

		Value allocated (\$000s)			
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase (\$000s)
Service interruptions and emergencies					
Directly attributable		84			
Not directly attributable				–	
Total attributable to regulated service		84			
Vegetation management					
Directly attributable		35			
Not directly attributable				–	
Total attributable to regulated service		35			
Routine and corrective maintenance and inspection					
Directly attributable		210			
Not directly attributable				–	
Total attributable to regulated service		210			
Asset replacement and renewal					
Directly attributable		80			
Not directly attributable				–	
Total attributable to regulated service		80			
System operations and network support					
Directly attributable		379			
Not directly attributable				–	
Total attributable to regulated service		379			
Business support					
Directly attributable		988			
Not directly attributable				–	
Total attributable to regulated service		988			
Operating costs directly attributable					
Operating costs not directly attributable	–	–	–	–	–
Operational expenditure		1,776			

Company Name **Nelson Electricity Ltd**
 For Year Ended **31 March 2016**

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

5d(ii): Other Cost Allocations

Pass through and recoverable costs

(\$000)

Pass through costs

Directly attributable

99

Not directly attributable

Total attributable to regulated service

99

Recoverable costs

Directly attributable

3,386

Not directly attributable

Total attributable to regulated service

3,386

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

(\$000)

Change in cost allocation 1

Cost category

Original allocator or line items

New allocator or line items

Original allocation

New allocation

Difference

CY-1

Current Year (CY)

—

—

Rationale for change

(\$000)

Change in cost allocation 2

Cost category

Original allocator or line items

New allocator or line items

Original allocation

New allocation

Difference

CY-1

Current Year (CY)

—

—

Rationale for change

(\$000)

Change in cost allocation 3

Cost category

Original allocator or line items

New allocator or line items

Original allocation

New allocation

Difference

CY-1

Current Year (CY)

—

—

Rationale for change

* 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

Nelson Electricity Ltd

For Year Ended

31 March 2016

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

5e(i): Regulated Service Asset Values

	Value allocated (\$000s) Electricity distribution services
Subtransmission lines	
Directly attributable	98
Not directly attributable	
Total attributable to regulated service	98
Subtransmission cables	
Directly attributable	5,526
Not directly attributable	
Total attributable to regulated service	5,526
Zone substations	
Directly attributable	9,978
Not directly attributable	
Total attributable to regulated service	9,978
Distribution and LV lines	
Directly attributable	517
Not directly attributable	
Total attributable to regulated service	517
Distribution and LV cables	
Directly attributable	15,518
Not directly attributable	
Total attributable to regulated service	15,518
Distribution substations and transformers	
Directly attributable	3,559
Not directly attributable	
Total attributable to regulated service	3,559
Distribution switchgear	
Directly attributable	2,175
Not directly attributable	
Total attributable to regulated service	2,175
Other network assets	
Directly attributable	3,470
Not directly attributable	
Total attributable to regulated service	3,470
Non-network assets	
Directly attributable	259
Not directly attributable	
Total attributable to regulated service	259
Regulated service asset value directly attributable	41,100
Regulated service asset value not directly attributable	–
Total closing RAB value	41,100

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

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

† include additional rows if needed

Company Name

Nelson Electricity Ltd

For Year Ended

31 March 2016

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	6a(i): Expenditure on Assets	(\$000)	(\$000)
8	Consumer connection		0
9	System growth		15
10	Asset replacement and renewal		452
11	Asset relocations		–
12	Reliability, safety and environment:		
13	Quality of supply	–	
14	Legislative and regulatory	–	
15	Other reliability, safety and environment	–	
16	Total reliability, safety and environment		–
17	Expenditure on network assets		468
18	Expenditure on non-network assets		14
19			
20	Expenditure on assets		482
21	plus Cost of financing		
22	less Value of capital contributions		26
23	plus Value of vested assets		
24			
25	Capital expenditure		455
26	6a(ii): Subcomponents of Expenditure on Assets (where known)		(\$000)
27	Energy efficiency and demand side management, reduction of energy losses		
28	Overhead to underground conversion		
29	Research and development		
30	6a(iii): Consumer Connection		
31	Consumer types defined by EDB*	(\$000)	(\$000)
32	Group 3	0	
33	[EDB consumer type]		
34	[EDB consumer type]		
35	[EDB consumer type]		
36	[EDB consumer type]		
37	* include additional rows if needed		
38	Consumer connection expenditure		0
39			
40	less Capital contributions funding consumer connection expenditure		
41	Consumer connection less capital contributions		0
42	6a(iv): System Growth and Asset Replacement and Renewal		
43		System Growth	Asset Replacement and Renewal
44		(\$000)	(\$000)
45	Subtransmission	15	–
46	Zone substations	–	–
47	Distribution and LV lines	–	18
48	Distribution and LV cables	–	117
49	Distribution substations and transformers	(0)	169
50	Distribution switchgear	–	20
51	Other network assets	–	128
52	System growth and asset replacement and renewal expenditure	15	452
53	less Capital contributions funding system growth and asset replacement and renewal	26	
54	System growth and asset replacement and renewal less capital contributions	(11)	452
55			
56	6a(v): Asset Relocations		
57	Project or programme*	(\$000)	(\$000)
58	[Description of material project or programme]		
59	[Description of material project or programme]		
60	[Description of material project or programme]		
61	[Description of material project or programme]		
62	[Description of material project or programme]		
63	* include additional rows if needed		
64	All other projects or programmes - asset relocations		
65	Asset relocations expenditure		–
66	less Capital contributions funding asset relocations		
67	Asset relocations less capital contributions		–

Company Name

Nelson Electricity Ltd

For Year Ended

31 March 2016

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

68				
69	6a(vi): Quality of Supply			
70	Project or programme*	(\$000)	(\$000)	
71	[Description of material project or programme]			
72	[Description of material project or programme]			
73	[Description of material project or programme]			
74	[Description of material project or programme]			
75	[Description of material project or programme]			
76	* include additional rows if needed			
77	All other projects programmes - quality of supply			
78	Quality of supply expenditure			—
79	less Capital contributions funding quality of supply			
80	Quality of supply less capital contributions			—
81	6a(vii): Legislative and Regulatory			
82	Project or programme*	(\$000)	(\$000)	
83	[Description of material project or programme]			
84	[Description of material project or programme]			
85	[Description of material project or programme]			
86	[Description of material project or programme]			
87	[Description of material project or programme]			
88	* include additional rows if needed			
89	All other projects or programmes - legislative and regulatory			
90	Legislative and regulatory expenditure			—
91	less Capital contributions funding legislative and regulatory			
92	Legislative and regulatory less capital contributions			—
93	6a(viii): Other Reliability, Safety and Environment			
94	Project or programme*	(\$000)	(\$000)	
95	[Description of material project or programme]			
96	[Description of material project or programme]			
97	[Description of material project or programme]			
98	[Description of material project or programme]			
99	[Description of material project or programme]			
100	* include additional rows if needed			
101	All other projects or programmes - other reliability, safety and environment			
102	Other reliability, safety and environment expenditure			—
103	less Capital contributions funding other reliability, safety and environment			
104	Other reliability, safety and environment less capital contributions			—
105				
106	6a(ix): Non-Network Assets			
107	Routine expenditure			
108	Project or programme*	(\$000)	(\$000)	
109	[Description of material project or programme]			
110	[Description of material project or programme]			
111	[Description of material project or programme]			
112	[Description of material project or programme]			
113	[Description of material project or programme]			
114	* include additional rows if needed			
115	All other projects or programmes - routine expenditure		14	
116	Routine expenditure			14
117	Atypical expenditure			
118	Project or programme*	(\$000)	(\$000)	
119	[Description of material project or programme]			
120	[Description of material project or programme]			
121	[Description of material project or programme]			
122	[Description of material project or programme]			
123	[Description of material project or programme]			
124	* include additional rows if needed			
125	All other projects or programmes - atypical expenditure			
126	Atypical expenditure			—
127				
128	Expenditure on non-network assets			14

Company Name

Nelson Electricity Ltd

For Year Ended

31 March 2016

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	6b(i): Operational Expenditure		
8	Service interruptions and emergencies	84	
9	Vegetation management	35	
10	Routine and corrective maintenance and inspection	210	
11	Asset replacement and renewal	80	
12	Network opex		409
13	System operations and network support	379	
14	Business support	988	
15	Non-network opex		1,367
16			
17	Operational expenditure		1,776
18	6b(ii): Subcomponents of Operational Expenditure (where known)		
19	Energy efficiency and demand side management, reduction of energy losses		
20	Direct billing*		
21	Research and development		
22	Insurance		110
23	* Direct billing expenditure by suppliers that directly bill the majority of their consumers		

Company Name	Nelson Electricity Ltd
For Year Ended	31 March 2016

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	7(i): Revenue	Target (\$000) ¹	Actual (\$000)	% variance
8	Line charge revenue	10,091	10,139	0%
9	7(ii): Expenditure on Assets	Forecast (\$000) ²	Actual (\$000)	% variance
10	Consumer connection		0	–
11	System growth	152	15	(90%)
12	Asset replacement and renewal	668	452	(32%)
13	Asset relocations		–	–
14	Reliability, safety and environment:			
15	Quality of supply		–	–
16	Legislative and regulatory		–	–
17	Other reliability, safety and environment	30	–	(100%)
18	Total reliability, safety and environment	30	–	(100%)
19	Expenditure on network assets	849	468	(45%)
20	Expenditure on non-network assets	20	14	(30%)
21	Expenditure on assets	870	482	(45%)
22	7(iii): Operational Expenditure			
23	Service interruptions and emergencies	147	84	(43%)
24	Vegetation management	51	35	(31%)
25	Routine and corrective maintenance and inspection	228	210	(8%)
26	Asset replacement and renewal	339	80	(76%)
27	Network opex	765	409	(47%)
28	System operations and network support	263	379	44%
29	Business support	1,081	988	(9%)
30	Non-network opex	1,344	1,367	2%
31	Operational expenditure	2,109	1,776	(16%)
32	7(iv): Subcomponents of Expenditure on Assets (where known)			
33	Energy efficiency and demand side management, reduction of energy losses		–	–
34	Overhead to underground conversion		–	–
35	Research and development		–	–
36				
37	7(v): Subcomponents of Operational Expenditure (where known)			
38	Energy efficiency and demand side management, reduction of energy losses		–	–
39	Direct billing		–	–
40	Research and development		–	–
41	Insurance		110	–
42				
43	¹ From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination			
44	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)			

Company Name
For Year Ended
Network / Sub-Network Name

Nelson Electricity Ltd
31 March 2016

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(i): Billed Quantities by Price Component

					Billed quantities by price component																	
					Price component	Streetlight	0-Bulkers Temporary	0-Unmetered	Group 1 Fixed	Group 1 Variable	Group 1 Distributed Generation	Group 2 Fixed	Group 2 Variable	Group 2 Distributed Generation	TOU - Capacity	TOU - Winter Demand	TOU - Installation	TOU - Variable	TOU - Power Factor	TOU Group 4	TOU Group 4 - Power Factor	TOU - Transmission
					Unit charging basis (e.g. days, kWh of demand, kVA of capacity, etc.)	Days	Days	Days	kVA	kWh	kWh	kVA	kWh	kWh	kVA	kVA	Days	kWh	kVAh	Month	kVAh	Month
Consumer group name or price category code	Consumer type or types (e.g. 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)																		
Load Group 0	Unmetered	Standard	51	1,196		366	5,926	10,532														
Load Group 1	Residential Low User	Standard	3,268	16,908					16,508,310	16,908,461	84,680											
Load Group 2	Residential and Small Business	Standard	5,785	65,130							43,811,839	65,130,160	144,433									
Load Group 3	Time of Use	Standard	91	34,077											10,197,858	3,907,233	32,940	34,076,873	7,951			
Load Group 4	Large TOU	Standard	1	13,708																12	--	
Load Group 5	Time of Use	Non-standard	2	9,306											1,427,400	658,583	732	9,305,849	450			24
Add extra rows for additional consumer groups or price category codes as necessary																						
Standard consumer totals			9,201	131,013		366	5,926	10,532	16,508,310	16,908,461	84,680	43,811,839	65,130,160	144,433	10,197,858	3,907,233	32,940	34,076,873	7,951	12	--	--
Non-standard consumer totals			2	9,306		--	--	--	--	--	--	--	--	--	1,427,400	658,583	732	9,305,849	450	--	--	24
Total for all consumers			9,203	140,319		366	5,926	10,532	16,508,310	16,908,461	84,680	43,811,839	65,130,160	144,433	11,625,258	4,566,216	33,672	43,382,722	8,401	12	--	24

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

Company Name
For Year Ended
Network / Sub-Network Name

Nelson Electricity Ltd
31 March 2016

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														
Streetlight														
0 Builders Temporary														
0 Unmetered														
Group 1 Fixed														
Group 1 Variable														
Group 1 Distributed Generation														
Group 2 Fixed														
Group 2 Variable														
Group 2 Distributed Generation														
TOU - Capacity														
TOU - Winter Demand														
TOU - Installation														
TOU - Variable														
TOU - Power Factor														
TOU Group 4														
TOU Group 4 - Power Factor														
TOU - Transmission														
Days														
Days														
Days														
KVA														
KWh														
KWh														
KVA														
KWh														
KWh														
KVA														
KVA														
Days														
KWh														
KVAh														
Month														
KVAh														
Month														
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														
National revenue foregone from posted discounts (if applicable)														
Total distribution line charge revenue														
Total transmission line charge revenue (if available)														
Rate (eg, 5 per day, 5 per kWh, etc.)														
Load Group 0														
Load Group 1														
Load Group 2														
Load Group 3														
Load Group 4														
Load Group 5														
Add extra rows for additional consumer groups or price category codes as necessary														
Standard consumer totals														
Non-standard consumer totals														
Total for all consumers														
8(iii): Number of ICPs directly billed														
Number of directly billed ICPs at year end														
Check														

Company Name **Nelson Electricity Ltd**For Year Ended **31 March 2016**

Network / Sub-network Name

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.	712	712	–	2
10	All	Overhead Line	Wood poles	No.	188	189	1	2
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1	–	(1)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	12	12	(0)	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	6	6	–	2
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.	1	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.	–	–	–	N/A
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	N/A
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	10	10	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	N/A
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	26	26	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	N/A
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	3	3	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	6	6	0	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	2	2	–	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	23	23	0	2
39	HV	Distribution Cable	Distribution UG PILC	km	51	51	(0)	2
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	1	1	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	41	41	–	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	25	25	–	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	47	47	–	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	261	261	–	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	18	16	(2)	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	181	182	1	3
48	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	N/A
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	182	182	–	2
50	LV	LV Line	LV OH Conductor	km	23	23	(0)	2
51	LV	LV Cable	LV UG Cable	km	173	172	(1)	2
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	71	69	(1)	2
53	LV	Connections	OH/UG consumer service connections	No.	9,213	9,207	(6)	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	75	75	–	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	1	1	–	4
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name
For Year Ended
Network / Sub-network Name

Nelson Electricity Ltd
31 March 2016

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 2016		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	2016							
9	All	Overhead Line	Concrete poles / steel structure	No.	21	1	43	247	91	136	36	7	6	27	2	9	8	7	9	9	26	8		3	1	2	12		1	712	(Select one)				
11	All	Overhead Line	Wood poles	No.	1	—	9	30	20	14	4	3	1	7	—	3	7	1	4	1	3	1	1	14	1	1	4	—	59	189	(Select one)				
12	All	Overhead Line	Other pole types	No.																											(Select one)				
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km			—																								(Select one)				
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																											(Select one)				
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km					4	0																8					(Select one)				
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km																											(Select one)				
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km																											(Select one)				
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km					3	2																					6	(Select one)			
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km																												(Select one)			
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km																												(Select one)			
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km																												(Select one)			
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km																												(Select one)			
23	HV	Subtransmission Cable	Subtransmission submarine cable	km																												(Select one)			
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.			—																				1	—			1	(Select one)			
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																												(Select one)			
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.																												(Select one)			
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.																												(Select one)			
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.																												(Select one)			
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.			—																									(Select one)			
30	HV	Zone substation switchgear	33kV RMU	No.																												(Select one)			
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.																							10				10	(Select one)			
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.						—	—																					(Select one)			
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.			—	—																			26				26	(Select one)			
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.																												(Select one)			
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.																							3	—			3	(Select one)			
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km			1	4	1			0										0		0							6	(Select one)			
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																												(Select one)			
38	HV	Distribution Line	SWER conductor	km					2												1	—	1	0	0	—	—	0	0		2	(Select one)			
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	—	—	—	0	4	14	3	0	—	—	—	—	0	—	—	—	1	—	1	0	0	—	—	0	0	—	—	23	(Select one)		
40	HV	Distribution Cable	Distribution UG PILC	km	1	—	0	7	13	6	2	3	—	0	1	0	2	3	0	0	1	3	2	2	1	1	1	—	—	—	51	(Select one)			
41	HV	Distribution Cable	Distribution Submarine Cable	km																												(Select one)			
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.																1											1	(Select one)			
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	—	—	—	—	17	16	—	—	—	—	—	—	—	—	—	—	—	—	8	—	—	—	—				41	(Select one)			
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	—	—	—	9	—	—	—	16																				25	(Select one)		
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	—	—	—	—	6	6	3	2	—	—	3	1	2	6	—	5	—	4	3	1	1	3	1				47	(Select one)			
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	—	—	—	9	51	67	16	10	—	1	6	9	7	31	8	3	15	13	7	2	2	4	—				261	(Select one)			
47	HV	Distribution Transformer	Pole Mounted Transformer	No.				1	3	3	1				1	1	2	3	—								1	—				16	(Select one)		
48	HV	Distribution Transformer	Ground Mounted Transformer	No.				4	6	34	23	2	4	6	4	6	15	15	10	8	7	12	5	5	3	3	3				182	(Select one)			
49	HV	Distribution Transformer	Voltage regulators	No.																												(Select one)			
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	4	—	1	20	42	61	15	6	1	3	4	3	3	5	—	3	3	2	1	2	1	1	1				182	(Select one)			
51	LV	LV Line	LV OH Conductor	km	—	0	—	0	11	4	7	0	0	—	—	—	0	—	—	0	—	—	—	—	—	0	0	0	—			23	(Select one)		
52	LV	LV Cable	LV UG Cable	km	—	0	—	0	23	43	43	12	1	1	2	1	3	4	2	3	3	3	1	3	2	1	1	0		21	172	(Select one)			
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	—	1	—	0	23	27	9	4	0	0	0	—	1	1	1	0	0	0	0	0	0	1	—	0	0			69	(Select one)		
54	LV	Connections	OH/UG consumer service connections	No.	—	—	—	—	2,239	504	6,268												35	45	26	56	34				9,207	(Select one)			
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	6	8	12	40	9				75	(Select one)			
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot													1														1	(Select one)			
57	All	Capacitor Banks	Capacitors including controls	Lot																												(Select one)			
58	All	Load Control	Centralised plant	No.			—			—																	1	—				1	(Select one)		
59	All	Load Control	Relays	No.																												(Select one)			
60	All	Civils	Cable Tunnels	km																												(Select one)			

Company Name

Nelson Electricity Ltd

For Year Ended

31 March 2016

Network / Sub-network Name

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	Circuit length by operating voltage (at year end)	Overhead (km)	Underground (km)
11	> 66kV		
12	50kV & 66kV		
13	33kV		17
14	SWER (all SWER voltages)	2	
15	22kV (other than SWER)		
16	6.6kV to 11kV (inclusive—other than SWER)	6	74
17	Low voltage (< 1kV)	23	172
18	Total circuit length (for supply)	31	264
19			
20	Dedicated street lighting circuit length (km)	1	68
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)		
22			
23	Overhead circuit length by terrain (at year end)	Circuit length (km)	(% of total overhead length)
24	Urban	29	94%
25	Rural		—
26	Remote only	2	6%
27	Rugged only		—
28	Remote and rugged		—
29	Unallocated overhead lines		—
30	Total overhead length	31	100%
31			
32		Circuit length (km)	(% of total circuit length)
33	Length of circuit within 10km of coastline or geothermal areas (where known)	295	100%
34		Circuit length (km)	(% of total overhead length)
35	Overhead circuit requiring vegetation management	31	100%

Company Name	Nelson Electricity Ltd
For Year Ended	31 March 2016

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			
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

Nelson Electricity Ltd

For Year Ended

31 March 2016

Network / Sub-network Name

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*

Load Group 0
Load Group 1
Load Group 2
Load Group 3
[EDB consumer type]

* include additional rows if needed

Connections total

Number of
connections (ICPs)

14
4
30
1

49

Distributed generation

Number of connections made in year

Capacity of distributed generation installed in year

22 connections

0.11 MVA

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

GXP demand

plus Distributed generation output at HV and above

Maximum coincident system demand

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

Demand on system for supply to consumers' connection points

Demand at time
of maximum
coincident
demand (MW)

33
-
33
33

Electricity volumes carried

Electricity supplied from GXPs

less Electricity exports to GXPs

plus Electricity supplied from distributed generation

less Net electricity supplied to (from) other EDBs

Electricity entering system for supply to consumers' connection points

less Total energy delivered to ICPs

Electricity losses (loss ratio)

Energy (GWh)

145
-
0
146
140
5

3.7%

Load factor

0.50

9e(iii): Transformer Capacity

Distribution transformer capacity (EDB owned)

Distribution transformer capacity (Non-EDB owned, estimated)

Total distribution transformer capacity

Zone substation transformer capacity

(MVA)

97
97
48

Company Name	Nelson Electricity Ltd
For Year Ended	31 March 2016
Network / Sub-network Name	

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	10(i): Interruptions		
9	Interruptions by class	Number of interruptions	
10	Class A (planned interruptions by Transpower)	–	
11	Class B (planned interruptions on the network)	11	
12	Class C (unplanned interruptions on the network)	5	
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	Total	16	
20			
21	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	4	1
23			
24	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.00	0.6
27	Class C (unplanned interruptions on the network)	0.22	10.4
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	Total	0.22	11.0
35			
36	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	0.08	5.8
38			
39	Quality path normalised reliability limit	SAIFI reliability limit	SAIDI reliability limit
40	SAIFI and SAIDI limits applicable to disclosure year*	0.24	22.2
41	* not applicable to exempt EDBs		

Company Name	Nelson Electricity Ltd
For Year Ended	31 March 2016
Network / Sub-network Name	

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	SAIFI	SAIDI
Lightning	–	–
Vegetation	–	–
Adverse weather	0.00	0.1
Adverse environment	–	–
Third party interference	–	–
Wildlife	0.14	3.5
Human error	0.01	0.0
Defective equipment	–	–
Cause unknown	0.06	6.8

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	–	–
Distribution cables (excluding LV)	0.00	0.0
Distribution other (excluding LV)	0.00	0.6

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.14	3.6
Distribution cables (excluding LV)	0.06	6.8
Distribution other (excluding LV)	0.01	0.0

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	–	1	–
Subtransmission cables	–	18	–
Subtransmission other	–		
Distribution lines (excluding LV)	3	6	50.00
Distribution cables (excluding LV)	1	74	1.35
Distribution other (excluding LV)	1		
Total	5		