Northpower

Disclosure Requirements 2014

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Northpower Limited
Information Disclosure for the Disclosure Year Ended 31 March 2014

Contents:

COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates
for
Schedules 1–10

Company Name	Northpower Limited
Disclosure Date	31 August 2014
Disclosure Year (year ended)	31 March 2014

Templates for Schedules 1–10
Template Version 3.0. Prepared 14 April 2014

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Disclosure Template Guidelines for Information Entry

These templates have been prepared for use by EDBs when making disclosures under subclauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, and 2.5.2 of the Electricity Distribution Information Disclosure Determination 2012. Disclosures must be made available to the public within 5 months after the end of the disclosure year and a copy provided to the Commission within 5 working days of being disclosed to the public.

Version 3.0 templates

These templates correct formula errors contained in previous versions of the templates. A list of the formula corrections can be found in the ID issues register under "Excel Template Issues - v2.X (2013)" in the category column. We have included additional guidance for schedules 2, 4 and 5a indicating where information for certain rows are expected to be sourced from.

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. Under no circumstances should the formulas in a calculated cell be overwritten.

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 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 P30 will change colour if P30 (overhead circuit length by terrain) does not equal P18 (overhead circuit length by operating voltage).
Schedule 4 cells P99:P105 and P107 will change colour if the RAB values do not equal the corresponding values in table 4(ii).

Inserting Additional Rows and Columns

The templates for schedules 4, 5b, 5c, 5d, 5e, 5i, 6a, 8, 9d, and 9e may require additional rows to be inserted in tables marked 'include additional rows if needed' or similar.
Additional rows in schedules 5c, 5i, 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 76 and 79 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 67:74, copy, select Excel row 76, insert copied cells. Similarly, for table 5e(ii): Select Excel rows 70:77, 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 1 October 2012). They provide a common reference between the rows in the determination and the template. Due to page formatting, the row reference sequences contained in the determination schedules are not necessarily contiguous.

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

Changes to disclosure year 2013
Clause 2.12 of the Electricity Distribution ID Determination 2012 does not apply for disclosure years 2014 and onwards. EDBs do not need to complete transitional schedules 5h and 5i. These schedules have been excluded from this version of the templates.
All schedules in this workbook must now be completed in full and publicly disclosed.

Schedule 2: Report on Return on Investment
The ROI calculations are performed in this template.
All suppliers must complete tables 2(i) Return on Investment and 2(ii) Information Supporting the ROI.
Only suppliers who meet either of the two thresholds set out in subclause 2.3.3 of the Electricity Distribution Information Disclosure Determination 2012 need to complete table 2(iii) Information Supporting the Monthly ROI. We expect that most suppliers will generally not meet either threshold. You will need to work out if you met either threshold using your own tools (e.g. Excel) and do not need to disclosure these calculations. If you met either threshold you will need to provide a breakdown of five cash flow items on a month by month basis, as well as your opening revenue related working capital. The definitions for these items are the same as for the rest of the schedules. The values for assets commissioned and asset disposals should relate to the RAB (not the unallocated RAB).
The Excel worksheet uses several calculated cells beyond the rightmost edge of the template to calculate the monthly
The prior year comparison information in the table 2(i) columns labelled CY-1 and CY-2 should be completed by copying the results from the previous year's disclosure.

Schedule 8: Report on Billed Quantities and Line Charge Revenues
This template should be completed in respect of each consumer groups or price category code (as applicable) that applied in the relevant disclosure year. The 'Average number of ICPs in disclosure year' column entries should be the arithmetic mean of monthly total ICPs (at month end).

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

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.

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	16,753	296	96,126	2,751	30,996
Network	8,635	152	49,547	1,418	15,977
Non-network	8,118	143	46,579	1,333	15,020
Expenditure on assets	18,027	318	103,440	2,960	33,355
Network	17,897	316	102,690	2,939	33,113
Non-network	131	2	750	21	242

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	62,193	1,097
Standard consumer line charge revenue	99,360	947
Non-standard consumer line charge revenue	18,511	1,171,857

1(iii): Service intensity measures

Demand density	29	*Maximum coincident system demand per km circuit length (for supply) (kW/km)*
Volume density	164	*Total energy delivered to ICPs per km circuit length (for supply) (MWh/km)*
Connection point density	9	*Average number of ICPs per km circuit length (for supply) (ICPs/km)*
Energy intensity	17,642	*Total energy delivered to ICPs per Average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	16,149	26.68%
Pass-through and recoverable costs	23,496	38.82%
Total depreciation	8,712	14.39%
Total revaluation	3,563	5.89%
Regulatory tax allowance	1,955	3.23%
Regulatory profit/loss	13,784	22.77%
Total regulatory income	60,533	

1(v): Reliability

	Interruptions per 100 circuit km
Interruption rate	11.55

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

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		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8		31 Mar 12	31 Mar 13	31 Mar 14
9	**Post tax WACC**	%	%	%
10	**ROI—comparable to a post tax WACC**	5.97%	5.54%	4.90%
12	**Mid-point estimate of post tax WACC**	6.40%	5.85%	5.43%
13	25th percentile estimate	5.68%	5.13%	4.71%
14	75th percentile estimate	7.11%	6.56%	6.14%
17	**Vanilla WACC**			
18	**ROI—comparable to a vanilla WACC**	6.75%	6.28%	5.59%
20	**Mid-point estimate of vanilla WACC**	7.22%	6.62%	6.11%
21	25th percentile estimate	6.51%	5.91%	5.39%
22	75th percentile estimate	7.94%	7.34%	6.83%

sch ref				($000)
24		**2(ii): Information Supporting the ROI**		
26		Total opening RAB value	232,435	
27	*plus*	Opening deferred tax	(2,737)	
28		Opening RIV		229,698
30		Operating surplus / (deficit)	20,888	
31	*less*	Regulatory tax allowance	1,955	
32	*less*	Assets commissioned	13,952	
33	*plus*	Asset disposals	-	
34		**Notional net cash flows**		4,981
36		Total closing RAB value	241,237	
37	*less*	Adjustment resulting from asset allocation	(0)	
38	*less*	Lost and found assets adjustment	-	
39	*plus*	Closing deferred tax	(3,822)	
40		**Closing RIV**		237,415
42		**ROI—comparable to a vanilla WACC**		5.59%
44		Leverage (%)		44%
45		Cost of debt assumption (%)		5.56%
46		Corporate tax rate (%)		28%
48		**ROI—comparable to a post tax WACC**		4.90%

Company Name	**Northpower Limited**
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SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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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

Cash flows ($000)	Total regulatory income	Expenses	Tax payments	Assets commissioned	Asset disposals	Notional net cash flows
April						-
May						-
June						-
July						-
August						-
September						-
October						-
November						-
December						-
January						-
February						-
March						-
Total	-	-	-	-	-	-

	Opening / closing RAB	Adjustment resulting from asset allocation	Lost and found assets adjustment	Opening / closing deferred tax	Revenue related working capital	Total
Monthly ROI - opening RIV	232,435			(2,737)		229,698
Monthly ROI -closing RIV	241,237	(0)	-	(3,822)	-	237,415
Monthly ROI -closing RIV less term credit spread differential allowance						237,415
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	5.82%
Year-end ROI—comparable to a post-tax WACC	5.14%

** 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.*

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

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 3(i), 3(iv) and 3(v) and must provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
Non-exempt EDBs must also complete sections 3(ii) and 3(iii).
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	59,953
10	*plus*	Gains / (losses) on asset disposals	-
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	580
12			
13		**Total regulatory income**	60,533
14		**Expenses**	
15	*less*	Operational expenditure	16,149
17	*less*	Pass-through and recoverable costs	23,496
18			
19		**Operating surplus / (deficit)**	20,888
20			
21	*less*	Total depreciation	8,712
22			
23	*plus*	Total revaluation	3,563
24			
25		**Regulatory profit / (loss) before tax & term credit spread differential allowance**	15,739
26			
27	*less*	Term credit spread differential allowance	-
28			
29		**Regulatory profit / (loss) before tax**	15,739
30			
31	*less*	Regulatory tax allowance	1,955
32			
33		**Regulatory profit / (loss)**	13,784
34			

sch ref			
35	**3(ii): Pass-Through and Recoverable Costs**		**($000)**
36	**Pass-through costs**		
37	Rates	59	
38	Commerce Act levies	19	
	Electricity Authority levies	120	
40	Other specified pass-through costs		
41	**Recoverable costs**		
42	Net recoverable costs allowed under incremental rolling incentive scheme		
43	Non-exempt EDB electricity lines service charge payable to Transpower	17,711	
44	Transpower new investment contract charges	-	
45	System operator services		
46	Avoided transmission charge	5,587	
47	Input Methodology claw-back		
48	Recoverable customised price-quality path costs		
49	**Pass-through and recoverable costs**		23,496

Company Name	**Northpower Limited**
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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 3(i), 3(iv) and 3(v) and must provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
Non-exempt EDBs must also complete sections 3(ii) and 3(iii).
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				
57	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
58			**CY-1**	**CY**
59			**31 March 2013**	**31 March 2014**
60	Allowed controllable opex			
61	Actual controllable opex			
62				
63	Incremental change in year			
64				
65			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
66	CY-5	31 Mar 09		
67	CY-4	31 Mar 10		
68	CY-3	31 Mar 11		
69	CY-2	31 Mar 12		
70	CY-1	31 Mar 13		
71	**Net incremental rolling incentive scheme**			-
72				
73	**Net recoverable costs allowed under incremental rolling incentive scheme**			-
74	**3(iv): Merger and Acquisition Expenditure**			
75	Merger and acquisition expenses			
76				
77	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)			
78	**3(v): Other Disclosures**			
79	Self-insurance allowance			

Company Name	Northpower Limited
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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			RAB	RAB	RAB	RAB	RAB
7		**4(i): Regulatory Asset Base Value (Rolled Forward)**					
8		for year ended	31 Mar 10	31 Mar 11	31 Mar 12	31 Mar 13	31 Mar 14
9			($000)	($000)	($000)	($000)	($000)
10		**Total opening RAB value**	208,746	213,178	223,506	228,670	232,435
11							
12	*less*	**Total depreciation**	9,023	9,432	8,274	8,549	8,712
13							
14	*plus*	**Total revaluations**	4,272	5,116	3,510	1,964	3,563
15							
16	*plus*	**Assets commissioned**	9,184	14,644	9,926	10,350	13,952
17							
18	*less*	**Asset disposals**					-
19							
20	*plus*	**Lost and found assets adjustment**					-
21							
22	*plus*	**Adjustment resulting from asset allocation**					(0)
23							
24		**Total closing RAB value**	213,178	223,506	228,670	232,435	241,237
25							

sch ref			Unallocated RAB *		RAB	
26		**4(ii): Unallocated Regulatory Asset Base**				
27						
28			($000)	($000)	($000)	($000)
29		**Total opening RAB value**		232,435		232,435
30	*less*					
31		**Total depreciation**		8,712		8,712
32	*plus*					
33		**Total revaluations**		3,563		3,563
34	*plus*					
35		Assets commissioned (other than below)	519		519	
36		Assets acquired from a regulated supplier	4,563		4,563	
37		Assets acquired from a related party	8,870		8,870	
38		**Assets commissioned**		13,952		13,952
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**		241,237		241,237

50 ** 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 non-regulated services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.*

Company Name: **Northpower Limited**
For Year Ended: **31 March 2014**

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			Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
58		**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**				
59						
60		CPI_4				1,192
61		CPI_4^{-4}				1,174
62		Revaluation rate (%)				1.53%
63						
66		Total opening RAB value	232,435		232,435	
67	*less*	Opening RAB value of fully depreciated, disposed and lost assets	53		53	
68						
69		Total opening RAB value subject to revaluation	232,382		232,382	
70		**Total revaluations**		3,563		3,563
71						

sch ref			Unallocated works under construction	Unallocated works under construction	Allocated works under construction	Allocated works under construction
72		**4(iv): Roll Forward of Works Under Construction**				
73						
74		**Works under construction—preceding disclosure year**		394		394
75	*plus*	Capital expenditure	15,660		15,660	
76	*less*	Assets commissioned	13,952		13,952	
77	*plus*	Adjustment resulting from asset allocation			-	
78		**Works under construction - current disclosure year**		2,102		2,102
79						
80		Highest rate of capitalised finance applied				4.13%

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For Year Ended: **31 March 2014**

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

88 ### 4(v): Regulatory Depreciation

sch ref		Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
89					
90					
91	Depreciation - standard	8,712		8,712	
92	Depreciation - no standard life assets				
93	Depreciation - modified life assets				
94	Depreciation - alternative depreciation in accordance with CPP				
95	**Total depreciation**		8,712		8,712
96					

97 ### 4(vi): Disclosure of Changes to Depreciation Profiles

($000 unless otherwise specified)

sch ref	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
98					
99					
100					
101					
102					
103					
104					
105					
106					

** include additional rows if needed*

107 ### 4(vii): Disclosure by Asset Category

108 ($000 unless otherwise specified)

sch ref			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
109												
110		**Total opening RAB value**	6323	7738	25000	90359	51197	29191	6832	5218	10577	232,435
111	*less*	Total depreciation	283	203	914	3273	1590	1400	306	501	243	8,712
112	*plus*	Total revaluations	97	119	383	1385	785	447	105	80	162	3,563
113	*plus*	Assets commissioned	1311	0	3976	5769	808	764	806	393	126	13,952
114	*less*	Asset disposals										-
115	*plus*	Lost and found assets adjustment										-
116	*plus*	Adjustment resulting from asset allocation										-
117	*plus*	Asset category transfers										-
118		**Total closing RAB value**	7,448	7,654	28,445	94,240	51,200	29,002	7,437	5,190	10,622	241,237
119												
120		**Asset Life**										
121		Weighted average remaining asset life	31.3	41.4	32.8	36.6	36.4	30.0	29.9	10.9	23.7	(years)
122		Weighted average expected total asset life	57.8	59.0	45.6	58.7	47.2	45.0	37.4	25.1	28.1	(years)

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For Year Ended	**31 March 2014**

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 2.8.

sch ref				
7	**5a(i): Regulatory Tax Allowance**			**($000)**
8	**Regulatory profit / (loss) before tax**			15,739
9				
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	- *	
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	2 *	
12		Amortisation of initial differences in asset values	4,536	
13		Amortisation of revaluations	563	
14				5,101
15				
16	*less*	Income included in regulatory profit / (loss) before tax but not taxable	3,563 *	
17		Discretionary discounts and consumer rebates	4,676	
18		Expenditure or loss deductible but not in regulatory profit / (loss) before tax**	- *	
19		Notional deductible interest	5,619	
20				13,858
21				
22	**Regulatory taxable income**			6,982
23				
24	*less*	Utilised tax losses	-	
25		Regulatory net taxable income		6,982
26				
27		Corporate tax rate (%)	28%	
28	**Regulatory tax allowance**			1,955
29				
30	* Workings to be provided in Schedule 14			
31	** Excluding discretionary discounts and consumer rebates			
32	**5a(ii): Disclosure of Permanent Differences**			
33		In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).		
34	**5a(iii): Amortisation of Initial Difference in Asset Values**			**($000)**
35				
36		Opening unamortised initial differences in asset values	132,823	
37		Amortisation of initial differences in asset values	4,536	
38		Adjustment for unamortised initial differences in assets acquired	-	
39		Adjustment for unamortised initial differences in assets disposed	-	
40		Closing unamortised initial differences in asset values		128,287
41				
42		Opening weighted average remaining asset life (years)		29
43	**5a(iv): Amortisation of Revaluations**			**($000)**
44				
45		Opening Sum of RAB values without revaluations	218,662	
46				
47		Adjusted depreciation	8,149	
48		Total depreciation	8,712	
49		Amortisation of revaluations		563

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

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 2.8.

sch ref				
57	**5a(v): Reconciliation of Tax Losses**			**($000)**
59		**Opening tax losses**	-	
60	*plus*	Current period tax losses	-	
61	*less*	Utilised tax losses	-	
62		**Closing tax losses**		-
63	**5a(vi): Calculation of Deferred Tax Balance**			**($000)**
65		**Opening deferred tax**	(2,737)	
67	*plus*	Tax effect of adjusted depreciation	2,282	
69	*less*	Tax effect of total tax depreciation	2,002	
71	*plus*	Tax effect of other temporary differences*	(95)	
73	*less*	Tax effect of amortisation of initial differences in asset values	1,270	
75	*plus*	Deferred tax balance relating to assets acquired in the disclosure year	-	
77	*less*	Deferred tax balance relating to assets disposed in the disclosure year		
79	*plus*	Deferred tax cost allocation adjustment	-	
81		**Closing deferred tax**		(3,822)
83	**5a(vii): Disclosure of Temporary Differences**			
84		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).		
86	**5a(viii): Regulatory Tax Asset Base Roll-Forward**			
87				**($000)**
88		**Opening sum of regulatory tax asset values**	76,493	
89	*less*	Tax depreciation	7,151	
90	*plus*	Regulatory tax asset value of assets commissioned	14,010	
91	*less*	Regulatory tax asset value of asset disposals	-	
92	*plus*	Lost and found assets adjustment	-	
93	*plus*	Other adjustments to the RAB tax value	-	
94		**Closing sum of regulatory tax asset values**		83,351

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

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

sch ref	5b(i): Summary—Related Party Transactions	($000)
8	Total regulatory income	
9	Operational expenditure	8,515
10	Capital expenditure	8,870
11	Market value of asset disposals	
12	Other related party transactions	

13 5b(ii): Entities Involved in Related Party Transactions

14	Name of related party	Related party relationship
15	Northpower Contracting Division	Division of Northpower. Supplier of electrical contracting services. Does not supply electricity distribution services.
16		
17		
18		
19		

20 ** include additional rows if needed*

21 5b(iii): Related Party Transactions

22	Name of related party	Related party transaction type	Description of transaction	Value of transaction ($000)	Basis for determining value
23	Northpower Contracting Division	Opex	Distribution System Maintenance	6,943	Price paid as more than 50% of the related party sales are to third parties
24	Northpower Contracting Division	Opex	Management fee	1,562	Price paid as more than 50% of the related party sales are to third parties
25	Northpower Contracting Division	Opex	Research and Development	10	Price paid as more than 50% of the related party sales are to third parties
26	Northpower Contracting Division	Capex	Construction of distribution system assets	8,870	Price paid as more than 50% of the related party sales are to third parties
27		[Select one]			
28		[Select one]			
29		[Select one]			
30		[Select one]			
31		[Select one]			
32		[Select one]			
33		[Select one]			
34		[Select one]			
35		[Select one]			
36		[Select one]			
37		[Select one]			

** include additional rows if needed*

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

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

7

8 ### 5c(i): Qualifying Debt (may be Commission only)

9

sch ref	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
11										
12										
13										
14										
15										
16	** include additional rows if needed*						-	-	-	-

17

18 ### 5c(ii): Attribution of Term Credit Spread Differential

sch ref			
19			
20	**Gross term credit spread differential**		-
21			
22	Total book value of interest bearing debt		
23	Leverage	44%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		-
26			
27	**Term credit spread differential allowance**		-

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

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

7 **5d(i): Operating Cost Allocations**

sch ref		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
8			Value allocated ($000s)			
10	**Service interruptions and emergencies**					
11	Directly attributable		1,814			
12	Not directly attributable				-	
13	Total attributable to regulated service		1,814			
14	**Vegetation management**					
15	Directly attributable		1,637			
16	Not directly attributable				-	
17	Total attributable to regulated service		1,637			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		2,101			
20	Not directly attributable				-	
21	Total attributable to regulated service		2,101			
22	**Asset replacement and renewal**					
23	Directly attributable		2,771			
24	Not directly attributable				-	
25	Total attributable to regulated service		2,771			
26	**System operations and network support**					
27	Directly attributable		2,534			
28	Not directly attributable				-	
29	Total attributable to regulated service		2,534			
30	**Business support**					
31	Directly attributable		1,605			
32	Not directly attributable		3,686	9,563	13,249	
33	Total attributable to regulated service		5,291			
34						
35	**Operating costs directly attributable**		12,464			
36	**Operating costs not directly attributable**	-	3,686	9,563	13,249	-
37	**Operating expenditure**		16,149			

45 **5d(ii): Other Cost Allocations**

sch ref		Electricity distribution services
46	**Pass through and recoverable costs**	
47	**Pass through costs**	
48	Directly attributable	198
49	Not directly attributable	
50	Total attributable to regulated service	198
51	**Recoverable costs**	
52	Directly attributable	23,298
53	Not directly attributable	
54	Total attributable to regulated service	23,298
55		

56 **5d(iii): Changes in Cost Allocations* †**

sch ref				CY-1	Current Year (CY)
56				($000)	
58	Change in cost allocation 1			31 Mar 13	31 Mar 14
59	Cost category		Original allocation		
60	Original allocator or line items		New allocation		
61	New allocator or line items		Difference	-	-
62					
63	Rationale for change				
64					
65				CY-1	Current Year (CY)
66	Change in cost allocation 2			31 Mar 13	31 Mar 14
67	Cost category		Original allocation		
68	Original allocator or line items		New allocation		
69	New allocator or line items		Difference	-	-
70					
71	Rationale for change				
72					
73				CY-1	Current Year (CY)
74	Change in cost allocation 3			31 Mar 13	31 Mar 14
75	Cost category		Original allocation		
76	Original allocator or line items		New allocation		
77	New allocator or line items		Difference	-	-
78					
79	Rationale for change				
80					
81					

82 ** 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	**Northpower Limited**
For Year Ended	**31 March 2014**

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

sch ref		Value allocated ($000s) Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	7080
12	Not directly attributable	368
13	Total attributable to regulated service	7448
14	**Subtransmission cables**	
15	Directly attributable	7654
16	Not directly attributable	
17	Total attributable to regulated service	7654
18	**Zone substations**	
19	Directly attributable	28445
20	Not directly attributable	
21	Total attributable to regulated service	28445
22	**Distribution and LV lines**	
23	Directly attributable	90869
24	Not directly attributable	3371
25	Total attributable to regulated service	94240
26	**Distribution and LV cables**	
27	Directly attributable	50995
28	Not directly attributable	205
29	Total attributable to regulated service	51200
30	**Distribution substations and transformers**	
31	Directly attributable	29002
32	Not directly attributable	
33	Total attributable to regulated service	29002
34	**Distribution switchgear**	
35	Directly attributable	7437
36	Not directly attributable	
37	Total attributable to regulated service	7437
38	**Other network assets**	
39	Directly attributable	5190
40	Not directly attributable	
41	Total attributable to regulated service	5190
42	**Non-network assets**	
43	Directly attributable	10622
44	Not directly attributable	
45	Total attributable to regulated service	10622
46		
47	**Regulated service asset value directly attributable**	237294
48	**Regulated service asset value not directly attributable**	3944
49	**Total closing RAB value**	241237

57 5e(ii): Changes in Asset Allocations* †

sch ref				($000) CY-1 31 Mar 13	Current Year (CY) 31 Mar 14
60	**Change in asset value allocation 1**				
61	Asset category		Original allocation		
62	Original allocator or line items		New allocation		
63	New allocator or line items		Difference	-	-
65	Rationale for change				

sch ref				CY-1 31 Mar 13	Current Year (CY) 31 Mar 14
68	**Change in asset value allocation 2**				
69	Asset category		Original allocation		
70	Original allocator or line items		New allocation		
71	New allocator or line items		Difference	-	-
73	Rationale for change				

sch ref				CY-1 31 Mar 13	Current Year (CY) 31 Mar 14
77	**Change in asset value allocation 3**				
78	Asset category		Original allocation		
79	Original allocator or line items		New allocation		
80	New allocator or line items		Difference	-	-
82	Rationale for change				

85 * 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	**Northpower Limited**
For Year Ended	**31 March 2014**

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			($000)	($000)
7		**6a(i): Expenditure on Assets**		
8		Consumer connection		1,909
9		System growth		4,797
10		Asset replacement and renewal		9,736
11		Asset relocations		144
12		Reliability, safety and environment:		
13		Quality of supply	368	
14		Legislative and regulatory	73	
15		Other reliability, safety and environment	225	
16		**Total reliability, safety and environment**		666
17		**Expenditure on network assets**		17,252
18		Non-network assets		126
19				
20		**Expenditure on assets**		17,378
21	*plus*	Cost of financing		
22	*less*	Value of capital contributions		2,019
23	*plus*	Value of vested assets		301
24				
25		**Capital expenditure**		15,660

sch ref		($000)
26	**6a(ii): Subcomponents of Expenditure on Assets (where known)**	
27	Energy efficiency and demand side management, reduction of energy losses	-
28	Overhead to underground conversion	-
29	Research and development	-

sch ref			($000)	($000)
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	($000)	($000)
32		All consumer types	742	
33		Large Industrial	1,167	
34		[EDB consumer type]		
35		[EDB consumer type]		
36		[EDB consumer type]		
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		1,909
39				
40	*less*	Capital contributions funding consumer connection expenditure		
41		**Consumer connection less capital contributions**		1,909

sch ref			System Growth ($000)	Asset Replacement and Renewal ($000)
42		**6a(iv): System Growth and Asset Replacement and Renewal**		
45		Subtransmission	1,153	267
46		Zone substations	3,516	416
47		Distribution and LV lines	-	4,586
48		Distribution and LV cables	41	3,062
49		Distribution substations and transformers	33	1,068
50		Distribution switchgear	-	32
51		Other network assets	54	305
52		**System growth and asset replacement and renewal expenditure**	4,797	9,736
53	*less*	Capital contributions funding system growth and asset replacement and renewal		2,019
54		**System growth and asset replacement and renewal less capital contributions**	4,797	7,717
55				

sch ref			($000)	($000)
56		**6a(v): Asset Relocations**		
57		*Project or programme**	($000)	($000)
58		Network asset relocations due to road improvements	144	
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 asset relocations projects or programmes		
65		**Asset relocations expenditure**		144
66	*less*	Capital contributions funding asset relocations		
67		**Asset relocations less capital contributions**		144

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

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				
75		**6a(vi): Quality of Supply**		
76		*Project or programme**	**($000)**	**($000)**
77		Control Centre improvements	180	
78		Communications improvements	188	
79				
80				
81				
82		** include additional rows if needed*		
83		All other quality of supply projects or programmes		
84		**Quality of supply expenditure**		368
85	*less*	Capital contributions funding quality of supply		
86		**Quality of supply less capital contributions**		368
87		**6a(vii): Legislative and Regulatory**		
88		*Project or programme**	**($000)**	**($000)**
89		Miscellaneous	73	
90		[Description of material project or programme]		
91		[Description of material project or programme]		
92		[Description of material project or programme]		
93		[Description of material project or programme]		
94		** include additional rows if needed*		
95		All other legislative and regulatory projects or programmes		
96		**Legislative and regulatory expenditure**		73
97	*less*	Capital contributions funding legislative and regulatory		
98		**Legislative and regulatory less capital contributions**		73
99		**6a(viii): Other Reliability, Safety and Environment**		
100		*Project or programme**	**($000)**	**($000)**
101		Improvements to distribution reliability	92	
102		Improvements to zone substation reliability	133	
103		[Description of material project or programme]		
104		[Description of material project or programme]		
105		[Description of material project or programme]		
106		** include additional rows if needed*		
107		All other reliability, safety and environment projects or programmes		
108		**Other reliability, safety and environment expenditure**		225
109	*less*	Capital contributions funding other reliability, safety and environment		
110		**Other reliability, safety and environment less capital contributions**		225
111				
112		**6a(ix): Non-Network Assets**		
113		**Routine expenditure**		
114		*Project or programme**	**($000)**	**($000)**
115		Computer cabling and security	67	
116		Vehicles	46	
117		Furniture	2	
118		Tools, Plant & Equipments	11	
119		[Description of material project or programme]		
120		** include additional rows if needed*		
121		All other routine expenditure projects or programmes		
122		**Routine expenditure**		126
123		**Atypical expenditure**		
124		*Project or programme**	**($000)**	**($000)**
125			-	
126			-	
127			-	
128		[Description of material project or programme]		
129		[Description of material project or programme]		
130		** include additional rows if needed*		
131		All other atypical expenditure projects or programmes		
132		**Atypical expenditure**		-
133				
134		**Non-network assets expenditure**		126

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

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

This schedule requires a breakdown of operating 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 operating 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			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	1,814	
9	Vegetation management	1,637	
10	Routine and corrective maintenance and inspection	2,101	
11	Asset replacement and renewal	2,771	
12	**Network opex**		8,324
13	System operations and network support	2,534	
14	Business support	5,291	
15	**Non-network opex**		7,825
16			
17	**Operational expenditure**		16,149
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		48
22	Insurance		115
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

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	57,291	59,953	5%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	800	1,909	139%
11	System growth	380	4,797	1,162%
12	Asset replacement and renewal	9,194	9,736	6%
13	Asset relocations	280	144	(49%)
14	Reliability, safety and environment:			
15	Quality of supply	1,390	368	(74%)
16	Legislative and regulatory	150	73	(51%)
17	Other reliability, safety and environment	230	225	(2%)
18	**Total reliability, safety and environment**	1,770	666	(62%)
19	**Expenditure on network assets**	12,424	17,252	39%
20	Non-network capex	523	126	(76%)
21	**Expenditure on assets**	12,947	17,378	34%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,316	1,814	38%
24	Vegetation management	1,519	1,637	8%
25	Routine and corrective maintenance and inspection	1,375	2,101	53%
26	Asset replacement and renewal	2,279	2,771	22%
27	**Network opex**	6,489	8,324	28%
28	System operations and network support	4,764	2,534	(47%)
29	Business support	4,205	5,291	26%
30	**Non-network opex**	8,969	7,825	(13%)
31	**Operational expenditure**	15,458	16,149	4%
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	84	48	(43%)
41	Insurance	121	115	(5%)
42				

43 *1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of the Determination*

44 *2 From the nominal dollar expenditure forecast and disclosed in the second to last AMP as the year CY+1 forecast*

Company Name	Northpower Limited
For Year Ended	31 March 2014
Network / Sub-Network Name	

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

sch ref	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)
15	Mass Market	Residential, small commercial	Standard	54,574	441,046
16	Commercial and Industrial	Commercial (ND9 only)	Standard	60	79,788
17	Very Large Industrial	Industrial	Non-standard	7	443,144
18			[Select one]		
19			[Select one]		
20			[Select one]		
21			[Select one]		
22			[Select one]		
23			[Select one]		
24			[Select one]		
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			Standard consumer totals	54,634	520,834
27			Non-standard consumer totals	7	443,144
28			Total for all consumers	54,641	963,978

Billed quantities by price component

sch ref	Price component	Mass Market Daily Supply Charge	Mass Market Variable Charge	C&I kWh charge	C&I demand	Large industrial distribution component	Large industrial transmission component
13	Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	days	MWh	MWh	kVA of demand	Asset based	Relevant portion of GXP connection charge
15			441,046				
16				79,788			
17						442,966	
18							
19							
20							
21							
22							
23							
24							
26		-	441,046	79,788	-	-	-
27		-	-	-	-	442,966	-
28		-	441,046	79,788	-	442,966	-

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

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**
Network / Sub-Network Name	

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

38 **8(ii): Line Charge Revenues ($000) by Price Component**

sch ref	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 (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Line charge revenues ($000) by price component: Mass Market Daily Supply Charge	Mass Market Variable Charge	C&I Monthly charge	C&I Demand charge	Large industrial Distribution component	Large Industrial Transmission Component
42							Rate (eg, $/day, $/kWh, etc.)	$/day	$/kWh	$/month	$/kVA/month	$/month	$/kW/month
44	Mass Market	Residential, small commercial	Standard	$48,184		$48,184		$4,485	$43,699				
45	Commercial and Industrial	Commercial (NO9 only)	Standard	$3,566		$3,566				$86	$3,480		
46	Very Large Industrial	Industrial	Non-standard	$8,203		$1,543	$6,660					$1,543	$6,660
47			[Select one]	-									
48			[Select one]	-									
49			[Select one]	-									
50			[Select one]	-									
51			[Select one]	-									
52			[Select one]	-									
53			[Select one]	-									
55			**Standard consumer totals**	$51,750	-	$51,750	-	$4,485	$43,699	$86	$3,480	-	-
56			**Non-standard consumer totals**	$8,203	-	$1,543	$6,660	-	-	-	-	$1,543	$6,660
57			**Total for all consumers**	$59,953	-	$53,293	$6,660	$4,485	$43,699	$86	$3,480	$1,543	$6,660

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

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

Check OK

59 **8(iii): Number of ICPs directly billed**

60 **Number of directly billed ICPs at year end** 4

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**
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

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy 1–4
9	All	Overhead Line	Concrete poles / steel structure	No.	53,627	53,791	164	3
10	All	Overhead Line	Wood poles	No.	1,269	1,168	(101)	3
11	All	Overhead Line	Other pole types	No.	4	3	(1)	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	219	293	74	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km		-	-	
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	8	8	-	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	8	8	-	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km		-	-	
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	3	3	-	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km		-	-	
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km		-	-	
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km		-	-	
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km		-	-	
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	1	1	-	4
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	20	21	1	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.		-	-	
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.		-	-	
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.		6	6	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	28	9	(19)	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	168	169	1	2
29	HV	Zone substation switchgear	33kV RMU	No.		4	4	1
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	25	25	-	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	49	59	10	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	144	145	1	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.		-	-	
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	32	46	14	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3,492	3,496	4	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km		-	-	
37	HV	Distribution Line	SWER conductor	km		-	-	
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	218	210	(8)	4
39	HV	Distribution Cable	Distribution UG PILC	km	20	35	15	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	2	2	-	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	32	30	(2)	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.		-	-	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	7,349	8,185	836	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	29	29	-	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	170	173	3	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	5,717	5,743	26	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,313	1,320	7	4
48	HV	Distribution Transformer	Voltage regulators	No.	4	4	-	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.		117	117	2
50	LV	LV Line	LV OH Conductor	km	1,204	1,202	(2)	3
51	LV	LV Cable	LV UG Cable	km	595	614	19	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	382	387	5	3
53	LV	Connections	OH/UG consumer service connections	No.	54,393	54,829	436	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	336	349	13	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	28	28	-	3
57	All	Load Control	Centralised plant	Lot	6	6	-	4
58	All	Load Control	Relays	No	30,660	31,439	779	1
59	All	Civils	Cable Tunnels	km			-	

Company Name	Northpower Limited
For Year Ended	31 March 2014
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.

sch ref

Disclosure Year (year ended): 31 March 2014

Number of assets at disclosure year end by installation date

sch ref	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	No. with Age unknown	Total assets at year end	No. with default dates	Data accuracy (1–4)
9																														
10	All	Overhead Line	Concrete poles / steel structure	No	19	42	1,364	7,734	8,000	8,803	7,250	596	576	529	779	882	797	791	612	559	694	721	666	706	601	123	10,948	53,791	10,948	3
11	All	Overhead Line	Wood poles	No.			28	111	65	64	133	8	10	18	34	45	28	20	8	6	3	4	6	2	2		575	2,168	575	3
12	All	Overhead Line	Other pole types	No.			1				1																1	3	1	3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km			72	104	26	38	45	4			1									2			1	293		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km																										4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km								1	1								4							8		4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km				5	3																			8		4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km																										4
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km						3																		3		4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km																										4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km																										4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km																										4
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km																										4
23	HV	Subtransmission Cable	Subtransmission submarine cable	km							1																	1		4
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	1		2	8	1	4	1	1							1	2								21		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.																										4
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No																										4
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No								3	2			1												6		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No																	9							9		4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No									1	7		1	29	3	3	4				1	3	2	115	169	115	2
30	HV	Zone substation switchgear	33kV RMU	No																							4	4	4	1
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No	6					12				1					1		1	2						25		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No	9		1	4	3	7	15	6				5			3		2		1	1	2			59		4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No	10			16	11	6	1		5		4			3	7	19	11	20	9		1			145		4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No																										4
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	5		1		4	3	1	3	2	2	1	5		8	3	1	5		1		1			46		4
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	4	2	90	456	506	452	328	48	11	47	21	57	30	17	21	18	17	24	39	65	80	8	1,155	3,496	279	3
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																										4
48	HV	Distribution Line	SWER conductor	km																										4
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km					1	9	21	5	6	12	8	15	23	27	20	8	11	5	3	4	8	1	23	210	9	4
50	HV	Distribution Cable	Distribution UG PILC	km				3	8	8	3																11	35	6	3
51	HV	Distribution Cable	Distribution Submarine Cable	km																							2	2		4
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No									1		1		10		2	2	3	2		5	4			30		4
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No																										4
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1		7	123	248	369	571	80	41	90	92	115	164	139	135	288	503	366	492	432	410	65	3,450	8,185	3,450	3
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No					3	2				2		1	2										14	29	14	3
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.						3	11	2	4	3	1	7	38	27	6	11	33	4	1	9	9	3	1	173	1	4
57	HV	Distribution Transformer	Pole Mounted Transformer	No	128	202	195	739	639	517	1,280	188	146	164	142	188	165	171	219	127	148	47	139	88	94	3	19	5,743	19	4
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	3	4	18	193	196	176	162	36	36	40	29	58	83	90	71	26	37	46	3	1	9	1	2	1,320	2	4
59	HV	Distribution Transformer	Voltage regulators	No					1					1			1										1	4	1	3
60	HV	Distribution Substations	Ground Mounted Substation Housing	No				2	2	1	14		1	7						1			1				88	117	88	2
61	LV	LV Line	LV OH Conductor	km			15	81	78	79	90	5	4	8	8	8	6	7	6	6	7	5	5	3	3	1	777	1,202	176	3
62	LV	LV Cable	LV UG Cable	km				18	32	35	67	6	14	23	29	42	47	47	45	26	27	15	7	5	17	2	126	614	51	3
63	LV	LV Street lighting	LV OH/UG Streetlight circuit	km			1	30	30	30	44	1	4	2	3	6	10	11	11	5	17	1	1		2	1	180	387	178	3
64	LV	Connections	OH/UG consumer service connections	No.				4	7	11,846	24,620	1,497	833	885	1,115	1,227	1,176	1,105	1,050	857	774	736	589	639	643	157	2,734	54,829	2,734	4
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.				1		45	86	13	6	5	3	9	19	15	24	36	24	31	2	9	1	1	21	349	21	3
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot																1								1		4
67	All	Capacitor Banks	Capacitors including controls	No									1				4			1	5	8		3			6	28	6	3
68	All	Load Control	Centralised plant	Lot						2					1				2			1						6		4
69	All	Load Control	Relays	No																							31,439	31,439	31,439	3
70	All	Civils	Cable Tunnels	km																										[Select one]

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**
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)**	**Total circuit length (km)**
11	> 66kV			-
12	50kV & 66kV	75		75
13	33kV	218	20	238
14	SWER (all SWER voltages)			-
15	22kV (other than SWER)			-
16	6.6kV to 11kV (inclusive—other than SWER)	3,496	246	3,743
17	Low voltage (< 1kV)	1,201	614	1,815
18	**Total circuit length (for supply)**	4,991	880	5,871
19				
20	Dedicated street lighting circuit length (km)	176	211	387
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			113
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	658	13%	
25	Rural	4,333	87%	
26	Remote only		-	
27	Rugged only		-	
28	Remote and rugged		-	
29	Unallocated overhead lines		-	
30	**Total overhead length**	4,991	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	3,381	58%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management		-	

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

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

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	**Northpower Limited**
For Year Ended	**31 March 2014**
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				
8	**9e(i): Consumer Connections**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Mass Market		671	
12	Commercial and Industrial		-	
13	Very Large Industrial		-	
14	[EDB consumer type]			
15	[EDB consumer type]			
16	** include additional rows if needed*			
17	**Connections total**		671	
18				
19	**Distributed generation**			
20	Number of connections made in year		48	**connections**
21	Capacity of distributed generation installed in year		0.19	**MVA**
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26	GXP demand		159	
27	Distributed generation output at HV and above	*plus*	9	
28	**Maximum coincident system demand**		168	
29	Net transfers to (from) other EDBs at HV and above	*less*	-	
30	**Demand on system for supply to consumers' connection points**		168	
31	**Electricity volumes carried**		**Energy (GWh)**	**Energy (GWh)**
32	Electricity supplied from GXPs		976	
33	Electricity exports to GXPs	*less*	-	
34	Electricity supplied from distributed generation	*plus*	24	
35	Net electricity supplied to (from) other EDBs	*less*	-	
36	**Electricity entering system for supply to consumers' connection points**		1,000	
37	Total energy delivered to ICPs	*less*	964	
38	**Electricity losses (loss ratio)**		36	3.6%
39				
40	**Load factor**		1	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43	Distribution transformer capacity (EDB owned)		521	
44	Distribution transformer capacity (Non-EDB owned)		3	
45	**Total distribution transformer capacity**		524	
46				
47	**Zone substation transformer capacity**		319	

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**
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

10(i): Interruptions

sch ref	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	
11	Class B (planned interruptions on the network)	348
12	Class C (unplanned interruptions on the network)	328
13	Class D (unplanned interruptions by Transpower)	2
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**	678

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	263	65

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.23	52.1
27	Class C (unplanned interruptions on the network)	2.10	103.6
28	Class D (unplanned interruptions by Transpower)	0.39	18.5
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**	2.72	174.2

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	2.32	147.7

sch ref	Quality path normalised reliability limit	SAIFI reliability limit	SAIDI reliability limit
40	SAIFI and SAIDI limits applicable to disclosure year*		
41	** not applicable to exempt EDBs*		

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

sch ref	Cause	SAIFI	SAIDI
45	Lightning	0.07	2.7
46	Vegetation	0.30	17.9
47	Adverse weather	0.26	25.2
48	Adverse environment	0.00	0.1
49	Third party interference	0.26	19.6
50	Wildlife	0.15	3.7
51	Human error	0.04	0.2
52	Defective equipment	0.39	24.8
53	Cause unknown	0.62	9.4

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

sch ref	Main equipment involved	SAIFI	SAIDI
65	Subtransmission lines	0.00	0.2
66	Subtransmission cables		
67	Subtransmission other		
68	Distribution lines (excluding LV)	0.22	51.8
69	Distribution cables (excluding LV)		
70	Distribution other (excluding LV)		

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

sch ref	Main equipment involved	SAIFI	SAIDI
74	Subtransmission lines	0.40	2.4
75	Subtransmission cables		
76	Subtransmission other		
77	Distribution lines (excluding LV)	1.67	98.6
78	Distribution cables (excluding LV)	0.03	2.5
79	Distribution other (excluding LV)		

10(v): Fault Rate

sch ref	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
82	Subtransmission lines	17	293	5.80
83	Subtransmission cables			-
84	Subtransmission other			
85	Distribution lines (excluding LV)	311	3,496	8.90
86	Distribution cables (excluding LV)	6	246	2.44
87	Distribution other (excluding LV)			
88	**Total**	334		

COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates
for
Schedules 5f & 5g

Company Name	Northpower Limited
Disclosure Date	31 August 2014
Disclosure Year (year ended)	31 March 2014

Templates for Schedules 5f & 5g
Template Version 3.0. Prepared 14 April 2014

Table of Contents

Disclosure Template Guidelines for Information Entry

These templates have been prepared for use by EDBs when making disclosures under subclause 2.3.2 of the Electricity Distribution Information Disclosure Determination 2012. These disclosures (schedules 5f and 5g) are not required to be publicly disclosed, but must be disclosed to the Commission within 5 months and 5 working days after the end of the disclosure year.

Instructions for completing schedules 5f & 5g

When completing schedules 5f & 5g, EDBs are only required to report on cost or asset values that are not directly attributable. If EDBs do not have any cost or asset values that are not directly attributable, they should indicate this on EDBs are required to submit schedules 5f & 5g to the Commission even if they do not have any cost or asset values that are not directly attributable.

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 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. Under no circumstances should the formulas in a calculated cell be overwritten.

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.

Inserting Additional Rows

The templates for schedules 5f and 5g may require additional rows to be inserted in tables.

Additional rows 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.

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 1 October 2012). They provide a common reference between the rows in the determination and the template. Due to page formatting, the row reference sequences contained in the determination schedules are not necessarily contiguous.

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5d (Cost allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.

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

8 Have costs been allocated in aggregate using ACAM in accordance with clause 2.1.1(3) of the IM Determination? **No**

9

sch ref	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
10/11					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
12	**Service interruptions and emergencies**										
13	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
14	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
15	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
16	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
17	**Not directly attributable**						-	-	-	-	-
18	**Vegetation management**										
19	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
20	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
21	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
22	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
23	**Not directly attributable**						-	-	-	-	-
24	**Routine and corrective maintenance and inspection**										
25	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
26	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
27	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
28	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
29	**Not directly attributable**						-	-	-	-	-
30	**Asset replacement and renewal**										
31	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
32	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
33	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
34	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
35	**Not directly attributable**						-	-	-	-	-

Company Name	Northpower Limited
For Year Ended	31 March 2014

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5d (Cost allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.

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											
43	**System operations and network support**										
44	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
45	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
46	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
47	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
48	**Not directly attributable**						-	-	-	-	-
49	**Business support**										
50	Human Resources	ABAA	Headcount	Proxy	3.24%	96.76%		79	2,355	2,434	
51	Information Technology	ABAA	Number of Terminal	Proxy	9.14%	90.86%		445	4,426	4,871	
	Finance	ABAA	Revenue	Proxy	23.20%	76.80%		428	1,416	1,844	
52	Rent	ABAA	Floor Space	Causal	29.50%	70.50%		142	338	480	
53	Corporate/Executive/Board	ABAA	EBIT	Proxy	71.62%	28.38%		2,592	1,027	3,619	
54	**Not directly attributable**						-	3,686	9,563	13,249	-
55											
56	**Operating costs not directly attributable**						-	3,686	9,563	13,249	-
57											
58	**Pass through and recoverable costs**										
59	**Pass through costs**										
60	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
61	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
62	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
63	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
64	**Not directly attributable**						-	-	-	-	-
65	**Recoverable costs**										
66	Insert cost description	e.g. ABAA	Allocator 1	[Select one]						-	
67	Insert cost description	e.g. ABAA	Allocator 2	[Select one]						-	
68	Insert cost description	e.g. ABAA	Allocator 3	[Select one]						-	
69	Insert cost description	e.g. ABAA	Allocator 4	[Select one]						-	
70	**Not directly attributable**						-	-	-	-	-

** include additional rows if needed*

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5e (Report on Asset Allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.

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

8 Have assets been allocated in aggregate using ACAM in accordance with clause 2.1.1(3) of the IM Determination? | Yes

9

sch ref	Line Item*	Allocation methodology type	Allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
11					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
12	**Subtransmission lines**										
13	Poles	ACAM	Allocator 1	[Select one]	100.00%			368		368	
14	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
15	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
16	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
17	**Not directly attributable**						-	368	-	368	-
18	**Subtransmission cables**										
19	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
20	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
21	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
22	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
23	**Not directly attributable**						-	-	-	-	-
24	**Zone substations**										
25	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
26	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
27	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
28	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
29	**Not directly attributable**						-	-	-	-	-
30	**Distribution and LV lines**										
31	Poles	ACAM	Allocator 1	[Select one]	100.00%			3,371		3,371	
32	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
33	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
34	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
35	**Not directly attributable**						-	3,371	-	3,371	-
36	**Distribution and LV cables**										
37	Ducts and civils	ACAM	Allocator 1	[Select one]	100.00%			205		205	
38	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
39	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
40	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
41	**Not directly attributable**						-	205	-	205	-

Company Name	**Northpower Limited**
For Year Ended	**31 March 2014**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5e (Report on Asset Allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.

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											
49	**Distribution substations and transformers**										
50	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
51	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
52	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
53	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
54	**Not directly attributable**						-	-	-	-	-
55											
56	**Distribution switchgear**										
57	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
58	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
59	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
60	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
61	**Not directly attributable**						-	-	-	-	-
62	**Other network assets**										
63	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
64	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
65	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
66	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
67	**Not directly attributable**						-	-	-	-	-
68	**Non-network assets**										
69	Insert asset description	e.g. ABAA	Allocator 1	[Select one]						-	
70	Insert asset description	e.g. ABAA	Allocator 2	[Select one]						-	
71	Insert asset description	e.g. ABAA	Allocator 3	[Select one]						-	
72	Insert asset description	e.g. ABAA	Allocator 4	[Select one]						-	
73	**Not directly attributable**						-	-	-	-	-
74											
75	**Regulated service asset value not directly attributable**						-	3,944	-	3,944	-

** include additional rows if needed*

COMMERCE COMMISSION
NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates
for
Schedules 11a–13

Company Name	Northpower Ltd
Disclosure Date	1 April 2014
AMP Planning Period Start Date (first day)	1 April 2014

Templates for Schedules 11a–13 (Asset Management Plan)
Template Version 3.0. Prepared 13 December 2013

Table of Contents

Disclosure Template Guidelines for Information Entry

These templates have been prepared for use by EDBs when making disclosures under subclauses 2.6.1(4), 2.6.1(5) and 2.6.5(5) of the Electricity Distribution Information Disclosure Determination 2012. Disclosures made under subclauses 2.6.1(4) and 2.6.1(5) must be made before the start of each disclosure year. Disclosures made under subclauses 2.6.5(5) must be made within 5 months after the start of the disclosure year. The information disclosed under 2.6.5(5) should be identical to that disclosed under 2.6.1(4) and 2.6.1(5).

Under clause 2.6.3, EDBs can elect to complete and publicly disclose before the start of the disclosure year, an **AMP update**.
EDBs can elect to complete and publicly disclose an AMP update instead of a full AMP in the following years:
- 31 March 2014
- 31 March 2015

If electing to complete an AMP update, EDBs can choose to not complete and disclose Schedule 13: Report on Asset Management Maturity Table. Schedule 13 sheet should be removed if not completed.
If disclosing a Full AMP, EDBs must complete and disclose Schedule 13.

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 first day of the 10 year planning period 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 (planning period start date) is used to calculate disclosure years in the column headings that show above some of the tables. It is also used to calculate the AMP planning period dates 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. Under no circumstances should the formulas in a calculated cell be overwritten.

Validation Settings on Data Entry Cells

To maintain a consistency of format and to guard against errors in data entry, some data entry cells test entries for validity and accept only a limited range of values. For example, entries may be limited to a list of category names or to values between 0% and 100%.
Where this occurs, a validation message will appear when data is being entered.

Conditional Formatting Settings on Data Entry Cells

Schedule 12a columns G to K contains conditional formatting. The cells will change colour if the row totals do not add to 100%.

Inserting Additional Rows

The templates for schedules 11a, 12b and 12c may require additional rows to be inserted in tables marked 'include additional rows if needed'.
Additional rows 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.
For schedule 12b the formula for column J (Utilisation of Installed Firm Capacity %) will need to be copied into the inserted row(s).

Schedule 11a & 11b

Schedule 11a requires Capital and Operational Expenditure to be expressed in both nominal and constant prices.
The differences between the nominal and constant prices should reflect EDB expectations of the impact of changes in the costs of its labour, materials and other inputs (ie, inflationary pressures).

Schedule 12b(ii)

The purpose of schedule 12b(ii) is to disclose transformer capacity as at the end of the current year. As the information may not be available in time for disclosures made under subclause 2.6.1(4), but available for disclosures made under 2.6.5(5), EDBs can choose not to disclose transformer capacity under schedule 12b(ii). EDBs who do not disclose transformer capacity under schedule 12b(ii) must disclose the information in schedule 9e(iii). Accordingly, the Excel template has been modified to allow the value "N/A" to be entered into these input cells.

Schedule 12d Report Forecast Interruptions and Duration sub-network disclosures

If the supplier has sub-networks, schedule 12d must be completed for the network and for each sub-network. A copy of the schedule 12d worksheet must be made for each sub-network.

Schedule 13 Report on Asset Management Maturity

The name of the standard applied (eg, 'PAS55') must be entered in cell K4.

Company Name: **Northpower Ltd**
AMP Planning Period: **1 April 2014 – 31 March 2024**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8		for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
9	**11a(i): Expenditure on Assets Forecast**		**$000 (in nominal dollars)**										
10	Consumer connection		1,910	852	362	373	384	396	407	420	432	445	459
11	System growth		180	746	3,135	4,086	2,055	2,761	3,800	2,745	6,169	3,875	1,454
12	Asset replacement and renewal		8,553	9,927	8,751	9,070	9,832	10,924	9,482	9,230	10,515	10,277	10,337
13	Asset relocations		140	150	31	32	33	34	35	36	37	38	39
14	Reliability, safety and environment:												
15	Quality of supply		413	795	1,045	703	551	211	116	304	123	238	130
16	Legislative and regulatory		90	250	400	400	-	-	-	-	-	-	-
17	Other reliability, safety and environment		471	830	364	159	55	106	58	60	61	63	115
18	**Total reliability, safety and environment**		974	1,875	1,809	1,262	606	317	174	364	184	301	246
19	**Expenditure on network assets**		11,757	13,549	14,088	14,823	12,910	14,432	13,897	12,794	17,338	14,936	12,534
20	Non-network assets		520	845	577	113	116	120	123	127	131	135	139
21	**Expenditure on assets**		12,277	14,394	14,665	14,936	13,027	14,552	14,021	12,921	17,469	15,071	12,673
22													
23	Cost of financing	*plus*	123	144	147	149	130	146	140	129	175	151	127
24	Value of capital contributions	*less*	941	1,084	1,127	1,186	1,033	1,155	1,112	1,024	1,387	1,195	1,003
25	Value of vested assets	*plus*	118	135	141	148	129	144	139	128	173	149	125
26													
27	**Capital expenditure forecast**		11,577	13,590	13,826	14,047	12,253	13,687	13,188	12,155	16,430	14,177	11,923
28													
29	Value of commissioned assets		11,577	13,590	13,826	14,047	12,253	13,687	13,188	12,155	16,430	14,177	11,923
30			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
		for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
32			**$000 (in constant prices)**										
33	Consumer connection		1,910	827	342	342	342	342	342	342	342	342	342
34	System growth		180	725	2,955	3,739	1,826	2,425	3,182	2,232	4,870	2,970	1,082
35	Asset replacement and renewal		8,553	9,639	8,249	8,301	8,736	9,423	7,941	7,505	8,300	7,876	7,692
36	Asset relocations		140	150	30	30	30	30	30	30	30	30	30
37	Reliability, safety and environment:												
38	Quality of supply		413	772	984	643	490	182	97	247	97	182	97
39	Legislative and regulatory		90	243	377	366	-	-	-	-	-	-	-
40	Other reliability, safety and environment		471	807	343	146	49	92	49	49	49	49	86
41	**Total reliability, safety and environment**		974	1,822	1,704	1,155	539	274	146	296	146	231	183
42	**Expenditure on network assets**		11,757	13,163	13,280	13,567	11,473	12,494	11,641	10,405	13,688	11,449	9,328
43	Non-network assets		520	820	560	110	110	110	110	110	110	110	110
44	**Expenditure on assets**		12,277	13,983	13,840	13,677	11,583	12,604	11,751	10,515	13,798	11,559	9,438
45													
46	**Subcomponents of expenditure on assets (where known)**												
47	Energy efficiency and demand side management, reduction of energy losses		-	-	-	-	-	-	-	-	-	-	-
48	Overhead to underground conversion		-	-	-	-	-	-	-	-	-	-	-
49	Research and development		50	52	53	55	56	58	60	61	63	65	67

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2014 – 31 March 2024**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
58	for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
59	**Difference between nominal and constant price forecasts**	$000										
60	Consumer connection	-	25	20	31	42	54	65	78	90	103	117
61	System growth	-	21	180	347	229	336	617	513	1,299	905	372
62	Asset replacement and renewal	-	288	502	769	1,096	1,501	1,541	1,725	2,214	2,400	2,645
63	Asset relocations	-	-	1	2	3	4	5	6	7	8	9
64	Reliability, safety and environment:											
65	Quality of supply	-	23	61	60	61	29	19	57	26	55	33
66	Legislative and regulatory	-	7	23	34	-	-	-	-	-	-	-
67	Other reliability, safety and environment	-	23	21	13	6	14	9	11	13	15	29
68	**Total reliability, safety and environment**	-	53	105	107	67	43	28	68	39	70	63
69	**Expenditure on network assets**	-	386	808	1,256	1,437	1,938	2,257	2,390	3,650	3,487	3,206
70	Non-network assets	-	25	17	3	6	10	13	17	21	25	29
71	**Expenditure on assets**	-	411	825	1,259	1,444	1,948	2,270	2,407	3,671	3,512	3,235

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
73	for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19
74	**11a(ii): Consumer Connection**						
75	*Consumer types defined by EDB**	$000 (in constant prices)					
76	Very large industrial	1,400	485	-	-	-	-
77	Mass market	510	342	342	342	342	342
78	[EDB consumer type]						
79	[EDB consumer type]						
80	[EDB consumer type]						
81	**include additional rows if needed*						
82	**Consumer connection expenditure**	1,910	827	342	342	342	342
83	*less* Capital contributions funding consumer connection						
84	**Consumer connection less capital contributions**	1,910	827	342	342	342	342
85	**11a(iii): System Growth**						
86	Subtransmission	-	-	801	-	-	-
87	Zone substations	150	264	1,789	3,307	1,744	2,343
88	Distribution and LV lines	10	272	29	379	29	29
89	Distribution and LV cables	-	136	283	-	-	-
90	Distribution substations and transformers	20	53	53	53	53	53
91	Distribution switchgear	-	-	-	-	-	-
92	Other network assets	-	-	-	-	-	-
93	**System growth expenditure**	180	725	2,955	3,739	1,826	2,425
94	*less* Capital contributions funding system growth						
95	**System growth less capital contributions**	180	725	2,955	3,739	1,826	2,425

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2014 – 31 March 2024**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
103								
104		for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19
105	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
106		Subtransmission		2,219	19			
107		Zone substations	803	778	1,823	1,873	2,047	2,995
108		Distribution and LV lines	5,772	5,651	5,651	5,651	5,651	5,651
109		Distribution and LV cables	220	214	214	214	214	214
110		Distribution substations and transformers	396	495	495	495	495	495
111		Distribution switchgear	1,040	243	47	18	329	18
112		Other network assets	322	39		50		50
113		**Asset replacement and renewal expenditure**	8,553	9,639	8,249	8,301	8,736	9,423
114	*less*	Capital contributions funding asset replacement and renewal						
115		**Asset replacement and renewal less capital contributions**	8,553	9,639	8,249	8,301	8,736	9,423
116	**11a(v):Asset Relocations**							
117		*Project or programme**						
118		Western Hills Drive OHUG (SH1 widening)	-	50	-	-	-	-
119		SH1/Kensington Ave roundabout cable relocate	-	50	-	-	-	-
		SH1/Maunu Rd OHUG	50	-	-	-	-	-
120		Dargaville ripple plant relocation	-	20	-	-	-	-
121		Minor capital expenditure (relocation)	90	30	30	30	30	30
122		[Description of material project or programme]						
123		**include additional rows if needed*						
124		All other asset relocations projects or programmes						
125		**Asset relocations expenditure**	140	150	30	30	30	30
126	*less*	Capital contributions funding asset relocations						
127		**Asset relocations less capital contributions**	140	150	30	30	30	30
128								
129	**11a(vi):Quality of Supply**							
130		*Project or programme**						
131		New reclosers	12	-	85	-	-	85
132		Whakapara Feeder Express Line Extension to Hikurangi	-	-	485	-	-	
133		Maungaturoto 33kV circuit separation	-	-	-	229	-	
134		Operational management system		100				
135		Comms for remote control of motorised Sectos switches	250	243	243	243	243	
		Zone sub AC/DC panel upgrades		73				
		Whangarei City additional 11kV RMU's					150	
		11kV dropout sectionalisers		24				
		11kV fault passage indicators	25	74	74	74		
		Chipmill RTU and comms		15				
		Dargaville Town feeder rationalisation		146				
		Minor capital expenditure (improvements)	35	97	97	97	97	97
		Chip Mill earth switch removal	31					
		11kV feeder backstopping improvements	15					
		Fourth Avenue-Maunu Road 11kV cable link	45					
136		**include additional rows if needed*						
137		All other quality of supply projects or programmes						
138		**Quality of supply expenditure**	413	772	984	643	490	182
139	*less*	Capital contributions funding quality of supply						
140		**Quality of supply less capital contributions**	413	772	984	643	490	182
141								
142	**11a(vii): Legislative and Regulatory**							
143		*Project or programme**						

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2014 – 31 March 2024**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref								
144		Zone Sub Oil Containment	90	243	377	366	-	-
145		[Description of material project or programme]						
146		[Description of material project or programme]						
147		[Description of material project or programme]						
148		[Description of material project or programme]						
149		**include additional rows if needed*						
150		All other legislative and regulatory projects or programmes						
151		**Legislative and regulatory expenditure**	90	243	377	366	-	-
152	*less*	Capital contributions funding legislative and regulatory						
153		**Legislative and regulatory less capital contributions**	90	243	377	366	-	-

Company Name	Northpower Ltd
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SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
161							
162	for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19
163	**11a(viii): Other Reliability, Safety and Environment**						
164	*Project or programme**	$000 (in constant prices)					
165	Zone Substations Security improvement	100	97	100			
166	Replace VHF analog links with digital (mobile radio)		146				
	Abbey system comms upgrade	20	78				
	VHF coverage improvement		49				
167	Dsub MDI Meters	20	58				
	Network strategic spare store	25	73				
168	Research and development (component testing)		49	49	49	49	49
	Protection relay strategic spares		29	-	-	-	43
	Replace 1305 and 1315 Maungatapere (motorised Sectos)		34	-	-	-	-
	Distribution security improvement		97	97	-	-	-
	Backup control room	5				-	-
	VHF coverage improvement	15					
	Fibre link Maungaturoto	75					
	Scada server upgrade	2					
	Scada historian upgrade	9					
	Fibre link Bream Bay	200					
169	Equipment lock system improvement		97	97	97		
170	*include additional rows if needed*						
171	All other reliability, safety and environment projects or programmes						
172	**Other reliability, safety and environment expenditure**	471	807	343	146	49	92
173	*less* Capital contributions funding other reliability, safety and environment						
174	**Other reliability, safety and environment less capital contributions**	471	807	343	146	49	92
175							
176							
177							
178	**11a(ix): Non-Network Assets**						
179	**Routine expenditure**						
180	*Project or programme**						
181	Land and Buildings	45	45	45	45	45	45
182	Vehicles	32	32	32	32	32	32
183	Plant and Equipment	15	15	15	15	15	15
184	Computers	3	3	3	3	3	3
185	Furniture and Fittings	15	15	15	15	15	15
186	*include additional rows if needed*						
187	All other routine expenditure projects or programmes						
188	**Routine expenditure**	110	110	110	110	110	110
189	**Atypical expenditure**						
190	*Project or programme**						
191	Billing system upgrade	250	-	-	-	-	-
192	Outage management system replacement	160	160	-	-	-	-
193	Asset management system replacement	-	550	450	-	-	-
194	[Description of material project or programme]						
195	[Description of material project or programme]						
196	*include additional rows if needed*						
197	All other atypical projects or programmes						
198	**Atypical expenditure**	410	710	450	-	-	-
199							
200	**Non-network assets expenditure**	520	820	560	110	110	110

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SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
8	for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1,538	1,587	1,635	1,684	1,734	1,786	1,840	1,895	1,952	2,010	2,071
11	Vegetation management	1,600	1,668	1,718	1,770	1,823	1,877	1,934	1,992	2,051	2,113	2,176
12	Routine and corrective maintenance and inspection	2,476	2,643	2,722	2,804	2,888	2,975	3,064	3,156	3,251	3,348	3,449
13	Asset replacement and renewal	2,455	2,251	2,319	2,388	2,460	2,534	2,610	2,688	2,768	2,851	2,937
14	**Network Opex**	8,069	8,149	8,393	8,645	8,905	9,172	9,447	9,730	10,022	10,323	10,633
15	System operations and network support	2,776	2,859	2,945	3,033	3,124	3,218	3,314	3,414	3,516	3,622	3,730
16	Business support	5,368	5,529	5,695	5,866	6,042	6,223	6,410	6,602	6,800	7,004	7,214
17	**Non-network opex**	8,144	8,388	8,640	8,899	9,166	9,441	9,724	10,016	10,316	10,626	10,944
18	**Operational expenditure**	16,213	16,537	17,033	17,544	18,070	18,613	19,171	19,746	20,338	20,949	21,577

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
20	for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1,538	1,538	1,538	1,538	1,538	1,538	1,538	1,538	1,538	1,538	1,538
23	Vegetation management	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
24	Routine and corrective maintenance and inspection	2,476	2,566	2,566	2,566	2,566	2,566	2,566	2,566	2,566	2,566	2,566
25	Asset replacement and renewal	2,455	2,185	2,185	2,185	2,185	2,185	2,185	2,185	2,185	2,185	2,185
26	**Network Opex**	8,069	7,889	7,889	7,889	7,889	7,889	7,889	7,889	7,889	7,889	7,889
27	System operations and network support	2,776	2,776	2,776	2,776	2,776	2,776	2,776	2,776	2,776	2,776	2,776
28	Business support	5,368	5,368	5,368	5,368	5,368	5,368	5,368	5,368	5,368	5,368	5,368
29	**Non-network opex**	8,144	8,144	8,144	8,144	8,144	8,144	8,144	8,144	8,144	8,144	8,144
30	**Operational expenditure**	16,213	16,033	16,033	16,033	16,033	16,033	16,033	16,033	16,033	16,033	16,033
31	**Subcomponents of operational expenditure (where known)**											
32–33	Energy efficiency and demand side management, reduction of energy losses											
34	Direct billing*											
35	Research and Development	103	103	103	103	103	103	103	103	103	103	103
36	Insurance	108	108	108	108	108	108	108	108	108	108	108

37 ** Direct billing expenditure by suppliers that direct bill the majority of their consumers*

sch ref		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
40	for year ended	31 Mar 14	31 Mar 15	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20	31 Mar 21	31 Mar 22	31 Mar 23	31 Mar 24
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	49	97	146	196	248	302	357	414	472	533
43	Vegetation management	-	68	118	170	223	277	334	392	451	513	576
44	Routine and corrective maintenance and inspection	-	77	156	238	322	409	498	590	685	782	882
45	Asset replacement and renewal	-	66	134	203	275	349	425	503	583	666	752
46	**Network Opex**	-	260	504	756	1,016	1,283	1,558	1,841	2,133	2,434	2,744
47	System operations and network support	-	83	169	257	348	442	539	638	740	846	955
48	Business support	-	161	327	498	674	855	1,042	1,234	1,432	1,636	1,846
49	**Non-network opex**	-	244	496	755	1,022	1,297	1,580	1,872	2,172	2,482	2,801
50	**Operational expenditure**	-	504	1,000	1,511	2,038	2,580	3,138	3,713	4,306	4,916	5,544

Company Name	Northpower Ltd
AMP Planning Period	1 April 2014 – 31 March 2024

SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
7					Asset condition at start of planning period (percentage of units by grade)						
8											
9											
10	All	Overhead Line	Concrete poles / steel structure	No.	1%	36%	22%	19%	22%	3	4.00%
11	All	Overhead Line	Wood poles	No.	14%	8%	15%	15%	48%	3	20.00%
12	All	Overhead Line	Other pole types	No.	-	-	67%	-	33%	3	1.00%
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	6%	49%	36%	5%	4%	4	5.00%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km						N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	6%	45%	48%	1%	4	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	99%	1%	-	-	4	-
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	-	-	100%	-	-	4	-
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	-	-	100%	-	-	4	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	39%	30%	9%	22%	-	4	5.00%
25	HV	Zone substation Buildings	Zone substations 110kV+	No.						N/A	
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	24%	32%	16%	28%	-	4	5.00%
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	29%	15%	32%	24%	-	4	6.00%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	32%	68%	2	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	-	31%	69%	2	-
30	HV	Zone substation switchgear	33kV RMU	No.						N/A	
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.						N/A	
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	83%	17%	-	4	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	32%	13%	4%	51%	-	4	18.00%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.						N/A	

Company Name	**Northpower Ltd**
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SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref					Asset condition at start of planning period (percentage of units by grade)						
42											
43											
44	**Voltage**	**Asset category**	**Asset class**	**Units**	**Grade 1**	**Grade 2**	**Grade 3**	**Grade 4**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	13%	11%	6%	70%	-	4	10.00%
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2%	45%	22%	20%	11%	3	10.00%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km						N/A	
48	HV	Distribution Line	SWER conductor	km						N/A	
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	2%	9%	69%	20%	3	-
50	HV	Distribution Cable	Distribution UG PILC	km	-	26%	30%	2%	42%	3	5.00%
51	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	100%	1	-
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	9%	91%	-	4	-
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.						N/A	
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	6%	8%	10%	36%	40%	3	10.00%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	10%	7%	7%	28%	48%	3	10.00%
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	5%	9%	83%	3%	4	-
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	29%	17%	28%	26%	-	4	15.00%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	20%	26%	20%	34%	-	4	10.00%
59	HV	Distribution Transformer	Voltage regulators	No.	-	14%	-	72%	14%	3	-
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	2%	3%	18%	2%	75%	2	2.00%
61	LV	LV Line	LV OH Conductor	km	1%	38%	22%	22%	17%	3	5.00%
62	LV	LV Cable	LV UG Cable	km	-	10%	10%	58%	22%	3	-
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	4%	1%	9%	1%	85%	2	3.00%
64	LV	Connections	OH/UG consumer service connections	No.	-	29%	48%	18%	5%	4	5.00%
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	1%	25%	20%	48%	6%	3	10.00%
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot						N/A	
67	All	Capacitor Banks	Capacitors including controls	No.	-	-	3%	77%	20%	3	-
68	All	Load Control	Centralised plant	Lot	33%	17%	33%	17%	-	4	10.00%
69	All	Load Control	Relays	No.	-	-	-	-	100%	1	5.00%
70	All	Civils	Cable Tunnels	km						N/A	

Company Name	**Northpower Ltd**
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SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

12b(i): System Growth - Zone Substations

Existing Zone Substations	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
Alexander Street	14	15	N-1	5	93%	15	91%	No constraint within +5 years	
Bream Bay	4	-	N	2	-	-		Other	Single transformer substation - backfeed via distribution network
Dargaville	12	15	N-1	3	77%	15	81%	No constraint within +5 years	
Hikurangi	7	5	N-1	2	132%	5	138%	Transformer	Transfer load in event of contingency
Kaiwaka	2	-	N	2	-	-		Other	Single transformer substation - backfeed via distribution network
Kamo	11	15	N-1	3	73%	15	79%	No constraint within +5 years	
Kioreroa	10	20	N-1	2	50%	20	60%	No constraint within +5 years	
Mangawhai	6	5	N-1	2	120%	5	132%	Transformer	Transfer load in event of contingency
Mareretu	3	-	N	2	-	-		Other	Single transformer substation - backfeed via distribution network
Maungatapere	7	5	N-1	3	140%	5	132%	Transformer	Transfer load in event of contingency
Maungaturoto	8	8	N-1	2	100%	8	101%	No constraint within +5 years	
Ngunguru	3	-	N	2	-	-		Other	Single transformer substation - backfeed via distribution network
Onerahi	8	8	N-1	2	112%	8	117%	Transformer	Transfer load in event of contingency
Parua Bay	3	-	N	2	-	4	93%	No constraint within +5 years	
Poroti	3	-	N	3	-	-		Other	Single transformer substation - backfeed via distribution network
Ruakaka	6	10	N-1	2	63%	10	73%	No constraint within +5 years	
Ruawai	3	-	N	2	-	-		Other	Single transformer substation - backfeed via distribution network
Tikipunga	16	20	N-1	4	80%	20	84%	No constraint within +5 years	
Whangarei South	13	10	N-1	5	130%	10	109%	Transformer	Transfer load in event of contingency
					-				

[1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

12b(ii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	524
Distribution transformer capacity (Non-EDB owned)	3
Total distribution transformer capacity	527
Zone substation transformer capacity	313

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2014 – 31 March 2024**

SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref								
7	**12c(i): Consumer Connections**							
8	*Number of ICPs connected in year by consumer type*				*Number of connections*			
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
11	*Consumer types defined by EDB**							
12	Very large industrial		-	-	-	-	-	-
13	Commercial and Industrial (demand based ND9)		1	1	1	1	1	1
14	Mass market		680	690	725	750	775	800
15								
16								
17	**Connections total**		681	691	726	751	776	801
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		34	40	50	60	75	100
21	Installed connection capacity of distributed generation (MVA)		0	0	0	0	0	0
22	**12c(ii) System Demand**							
23			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24	**Maximum coincident system demand (MW)**	for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
25	GXP demand		159	161	168	172	176	179
26	*plus* Distributed generation output at HV and above		9	9	9	9	9	9
27	**Maximum coincident system demand**		168	170	177	181	185	188
28	*less* Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29	**Demand on system for supply to consumers' connection points**		168	170	177	181	185	188
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		976	986	996	1,006	1,016	1,026
32	*less* Electricity exports to GXPs		-	-	-	-	-	-
33	*plus* Electricity supplied from distributed generation		24	24	24	24	24	24
34	*less* Net electricity supplied to (from) other EDBs		-	-	-	-	-	-
35	**Electricity entering system for supply to ICPs**		1,000	1,010	1,020	1,030	1,040	1,050
36	*less* Total energy delivered to ICPs		965	975	984	994	1,004	1,014
37	**Losses**		35	35	36	36	36	36
38								
39	**Load factor**		68%	68%	66%	65%	64%	64%
40	**Loss ratio**		3.5%	3.5%	3.5%	3.5%	3.5%	3.4%

Company Name	**Northpower Ltd**
AMP Planning Period	**1 April 2014 – 31 March 2024**
Network / Sub-network Name	

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
9		for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		55.0	55.0	55.0	55.0	55.0	55.0
12	Class C (unplanned interruptions on the network)		90.0	88.0	86.0	84.0	82.0	80.0
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.24	0.24	0.24	0.24	0.24	0.24
15	Class C (unplanned interruptions on the network)		2.00	1.95	1.90	1.85	1.80	1.75

Schedule 13

Schedule 13 disclosure is only required in those years in which a full AMP is disclosed. A full AMP was disclosed in 2013 together with a schedule 13 report. Northpower elected to only disclose an AMP update in 2014 and the only requirement associated with that option is to identify any changes to asset management practices that would affect a schedule 13 report.

During the year, there are no changes to asset management practices that would affect the schedule 13 report disclosed in prior year.

Company Name	Northpower Limited
For Year Ended	31 March 2014

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 calculated post tax WACC and vanilla WACC for the disclosure year was 4.90% and 5.59%, respectively. The calculated return on investment was within the range of post tax WACC and vanilla WACC as determined by the Commission.

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
Other regulatory line income amounting to $580k includes value added work on charged to customers (circa $559k).

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
Not applicable – there were no incurred merger and acquisitions expenditures during the disclosure year.

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 RAB rollforward in Schedule 4 is determined in accordance with the requirements per IM. • There are no reclassifications made.

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
Discretionary discounts and rebates – not included in regulatory profit calculation however this was considered deductible for tax purposes. Entertainment expense not deductible for tax purposes.

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)
Other temporary differences in 5a(vi) of Schedule 5a represent expenditure capitalised in RAB but treated as deductible expenditure for tax purposes.

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

Related party transactions disclosed on schedule 5b all relate to services provided by Northpower Contracting division to the EDB. These include:

- Construction of distribution system assets recognised as capital expenditure were provided in accordance with Service Level agreement.
- Distribution system maintenance, management fee, and other services which are recognised as operating expenditure are provided in accordance with Service Level Agreement.

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

We have applied the accounting-based allocation approach (ABAA) in respect of allocating operating costs not directly attributable.

There are no items reclassified.

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
We have used avoidable cost allocation methodology (ACAM) in respect of allocating regulated service asset valued not directly attributable which consists of poles and ducts shared by both the EDB and the unregulated fibre business. We have determined ACAM as an appropriate allocation methodology as the total value of regulated service asset values not directly attributable less any arms-length deductions is less than 10% of the aggregate unallocated closing RAB value in accordance with clauses 2.2.2 (4)(b) of the IM.

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
Projects and programmes as stated in schedule 6a were very specific and adequately describe the nature of the projects and programmes.

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

- Asset replacement and renewal operating expenditure relate to work done to make good on defects identified during scheduled preventive maintenance inspections.
- There are no reclassified items to report.
- No material atypical expenditure included in the operational expenditure.

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

- Overall, actual capital expenditure on network assets was 39% higher than the target capital expenditure. Consumer connections expenditure was higher than forecast due to impact of policy change with respect to capacity charges not reflected in the forecast. System growth was higher than forecast due to transmission assets acquired from Transpower. Asset relocations were lower than forecast due to NZTA projects which started later than expected. Reliability, safety and environment costs was lower in FY 14 due to timing (or deferral) of implementation of the relevant projects planned for the year.
- Overall, actual network operating expenditure was 28% higher than the forecast. Higher network opex costs were mainly driven by increase in costs relating to service interruptions and emergencies, routine & corrective maintenance costs, as well as asset replacement and renewal.

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

Target revenue disclosed before the start of the year was lower (5%) than the total billed line charge revenue for the disclosure year. No material movement between target revenue and total billed line charge revenue noted.

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

SAIFI for the disclosure year was measured at 2.72 interruptions per customer.

Unplanned SAIDI for FY14 was 103.6 minutes which is higher than our target (per Statement of Corporate Intent) of 90 minutes. This is due to the effects of Cyclone Lusi.

The target for planned interruptions of 55 minutes was achieved with actual SAIDI score of 52.1 minutes.

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
Significant assets located in one place (e.g. zone substations, control room) are insured under a comprehensive replacement insurance policy. Assets that are spread over a large area (e.g. lines, cables and distribution transformers) are uninsured.

Company Name	Northpower Limited
For Year Ended	31 March 2014

Schedule 14a Mandatory Explanatory Notes on Forecast Information

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

1. This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.2. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

Commentary on difference between nominal and constant price capital expenditure forecasts (Schedule 11a)

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the disclosure year, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
The nominal prices are based on escalation rate of 3% per annum over the 10-year forecast period. The constant prices relate to the values excluding the 3% escalation rate.

Commentary on difference between nominal and constant price operational expenditure forecasts (Schedule 11b)

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the disclosure year, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
The opex forecasts (in nominal terms) increases by 3% going forward relative to opex in constant prices which is expected to remain stable over the 10-year forecast period.

Company Name	Northpower Limited
For Year Ended	31 March 2014

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
Nothing significant to report.

AUDIT NEW ZEALAND
Mana Arotake Aotearoa

Independent Auditor's Report

To the directors of Northpower Limited and to the Commerce Commission

The Auditor-General is the auditor of Northpower Limited (the company). The Auditor-General has appointed me, Pieterse, 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 31 March 2014, have been prepared, in all material respects, in accordance with the Electricity Distribution Information Disclosure 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 and its subsidiaries 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 and its subsidiaries.

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.

Leon Pieterse
Audit New Zealand
On behalf of the Auditor-General
Auckland, New Zealand
22 August 2014

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Certification for Year-end Disclosures

We, Nikki Davies-Colley and John Ward, being directors of Northpower Limited 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 and 2.3.2; and clauses 2.4.21 and 2.4.22; clauses 2.5.1 and 2.5.2; and clauses 2.7.1 and 2.7.2 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, 14a and 14b has been properly extracted from the Northpower Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained; and

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with Northpower Limited's corporate vision and strategy and are documented in retained records.

Director	Director
22 August 2014	22 August 2014
Date	Date