COMMERCE COMMISSION
NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates
for
Schedules 1–10

Company Name	Northpower Limited
Disclosure Date	31 August 2016
Disclosure Year (year ended)	31 March 2016

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

Table of Contents

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

Company Name **Northpower Limited**
For Year Ended **31 March 2016**

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with the ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of the determination. This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

sch ref		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)
7	**1(i): Expenditure metrics**					
8						
9	**Operational expenditure**	15,231	274	96,135	2,639	29,235
10	Network	8,596	154	54,258	1,489	16,500
11	Non-network	6,635	119	41,877	1,149	12,735
12						
13	**Expenditure on assets**	17,264	310	108,969	2,991	33,138
14	Network	17,035	306	107,521	2,951	32,698
15	Non-network	229	4	1,448	40	440
16						

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
17	**1(ii): Revenue metrics**		
18			
19	**Total consumer line charge revenue**	63,775	1,146
20	Standard consumer line charge revenue	105,686	993
21	Non-standard consumer line charge revenue	17,909	1,466,333
22			

sch ref			
23	**1(iii): Service intensity measures**		
24			
25	Demand density	27	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	173	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	10	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	17,972	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

sch ref		($000)	% of revenue
30	**1(iv): Composition of regulatory income**		
31			
32	Operational expenditure	15,670	23.78%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	20,044	30.41%
34	Total depreciation	9,439	14.32%
35	Total revaluations	1,421	2.16%
36	Regulatory tax allowance	4,620	7.01%
37	Regulatory profit/(loss) including financial incentives and wash-ups	17,556	26.64%
38	**Total regulatory income**	65,908	
39			

sch ref			
40	**1(v): Reliability**		
41			
42	Interruption rate	11.37	*Interruptions per 100 circuit km*

Company Name **Northpower Limited**
For Year Ended **31 March 2016**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).
EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7	**2(i): Return on Investment**	**CY-2**	**CY-1**	**Current Year CY**
8		**31 Mar 14**	**31 Mar 15**	**31 Mar 16**
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	5.23%	5.19%	6.67%
11	Excluding revenue earned from financial incentives	5.23%	5.19%	6.67%
12	Excluding revenue earned from financial incentives and wash-ups	5.23%	5.19%	6.67%
13				
14	**Mid-point estimate of post tax WACC**	5.43%	6.89%	5.37%
15	25th percentile estimate	4.71%	6.17%	4.66%
16	75th percentile estimate	6.14%	7.60%	6.09%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	5.92%	5.97%	7.31%
21	Excluding revenue earned from financial incentives	5.92%	5.97%	7.31%
22	Excluding revenue earned from financial incentives and wash-ups	5.92%	5.97%	7.31%
23				
24	**WACC rate used to set regulatory price path**			
25				
26	**Mid-point estimate of vanilla WACC**	6.11%	6.10%	6.02%
27	25th percentile estimate	5.39%	5.39%	5.30%
28	75th percentile estimate	6.83%	6.82%	6.74%
29				
30	**2(ii): Information Supporting the ROI**		**($000)**	
31				
32	Total opening RAB value	242,199		
33	*plus* Opening deferred tax	(4,676)		
34	**Opening RIV**		237,523	
35				
36	**Line charge revenue**		65,615	
37				
38	Expenses cash outflow	35,714		
39	*add* Assets commissioned	19,351		
40	*less* Asset disposals	–		
41	*add* Tax payments	3,473		
42	*less* Other regulated income	293		
43	**Mid-year net cash outflows**		58,245	
44				
45	**Term credit spread differential allowance**		–	
46				
47	Total closing RAB value	253,531		
48	*less* Adjustment resulting from asset allocation	0		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(5,823)		
51	**Closing RIV**		247,708	
52				
53	**ROI – comparable to a vanilla WACC**			7.31%
54				
55	Leverage (%)			44%
56	Cost of debt assumption (%)			5.26%
57	Corporate tax rate (%)			28%
58				
59	**ROI – comparable to a post tax WACC**			6.67%
60				

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).
EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).
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sch ref

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

Tax payments	N/A
Term credit spread differential allowance	N/A
Closing RIV	N/A
Monthly ROI – comparable to a vanilla WACC	N/A
Monthly ROI – comparable to a post tax WACC	N/A

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

Year-end ROI – comparable to a vanilla WACC	7.10%
Year-end ROI – comparable to a post tax WACC	6.45%

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

2(v): Financial Incentives and Wash-Ups

Net recoverable costs allowed under incremental rolling incentive scheme	–	
Purchased assets – avoided transmission charge		
Energy efficiency and demand incentive allowance		
Quality incentive adjustment		
Other financial incentives		
Financial incentives		–
Impact of financial incentives on ROI		–
Input methodology claw-back		
Recoverable customised price-quality path costs		
Catastrophic event allowance		
Capex wash-up adjustment		
Transmission asset wash-up adjustment		
2013–2015 NPV wash-up allowance		
Reconsideration event allowance		
Other wash-ups		
Wash-up costs		–
Impact of wash-up costs on ROI		–

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

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

sch ref			
7		**3(i): Regulatory Profit**	**($000)**
8		**Income**	
9		Line charge revenue	65,615
10	*plus*	Gains / (losses) on asset disposals	
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	293
12			
13		**Total regulatory income**	65,908
14		**Expenses**	
15	*less*	Operational expenditure	15,670
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	20,044
18			
19		**Operating surplus / (deficit)**	30,194
20			
21	*less*	Total depreciation	9,439
22			
23	*plus*	Total revaluations	1,421
24			
25		**Regulatory profit / (loss) before tax**	22,176
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	4,620
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	17,556
32			

sch ref			
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34	**Pass through costs**		
35	Rates	76	
36	Commerce Act levies	34	
37	Industry levies	177	
38	CPP specified pass through costs		
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	18,424	
41	Transpower new investment contract charges		
42	System operator services		
43	Distributed generation allowance		
44	Extended reserves allowance		
45	Other recoverable costs excluding financial incentives and wash-ups	1,333	
46	**Pass-through and recoverable costs excluding financial incentives and wash-ups**		20,044
47			

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

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

Company Name	Northpower Limited
For Year Ended	31 March 2016

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

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

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

sch ref							
7	**4(i): Regulatory Asset Base Value (Rolled Forward)**		**RAB**	**RAB**	**RAB**	**RAB**	**RAB**
8		for year ended	**31 Mar 12**	**31 Mar 13**	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**
9			**($000)**	**($000)**	**($000)**	**($000)**	**($000)**
10	**Total opening RAB value**		223,506	228,670	232,435	241,237	242,199
11							
12	*less* **Total depreciation**		8,274	8,549	8,712	9,821	9,439
13							
14	*plus* **Total revaluations**		3,510	1,964	3,563	202	1,421
15							
16	*plus* **Assets commissioned**		9,926	10,350	13,952	10,580	19,351
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**		228,670	232,435	241,237	242,199	253,531
25							

26	**4(ii): Unallocated Regulatory Asset Base**				
27		**Unallocated RAB ***		**RAB**	
28		**($000)**	**($000)**	**($000)**	**($000)**
29	**Total opening RAB value**		242,199		242,199
30	*less*				
31	**Total depreciation**		9,439		9,439
32	*plus*				
33	**Total revaluations**		1,421		1,421
34	*plus*				
35	Assets commissioned (other than below)	564		564	
36	Assets acquired from a regulated supplier	3,672		3,672	
37	Assets acquired from a related party	15,114		15,114	
38	**Assets commissioned**		19,351		19,351
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**		253,531		253,531

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 services provided by the supplier that are not electricity distribution services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.*

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

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

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

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

sch ref						
51						
52	**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**					
53						
54		CPI_4				1,200
55		CPI_4^{-4}				1,193
56		Revaluation rate (%)				0.59%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	242,199		242,199	
61	*less*	Opening value of fully depreciated, disposed and lost assets	61		61	
62						
63		Total opening RAB value subject to revaluation	242,138		242,138	
64		**Total revaluations**		1,421		1,421
65						
66	**4(iv): Roll Forward of Works Under Construction**					
67			**Unallocated works under construction**		**Allocated works under construction**	
68		**Works under construction—preceding disclosure year**		3,215		3,215
69	*plus*	Capital expenditure	16,204		16,204	
70	*less*	Assets commissioned	19,351		19,351	
71	*plus*	Adjustment resulting from asset allocation				
72		**Works under construction - current disclosure year**		68		68
73						
74		Highest rate of capitalised finance applied				4.39%
75						

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

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

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

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

sch ref

76 4(v): Regulatory Depreciation

sch ref		Unallocated RAB *		RAB	
78		($000)	($000)	($000)	($000)
79	Depreciation - standard	9,439		9,439	
80	Depreciation - no standard life assets				
81	Depreciation - modified life assets				
82	Depreciation - alternative depreciation in accordance with CPP				
83	**Total depreciation**		9,439		9,439
84					

85 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
87					
88					
89					
90					
91					
92					
93					
94					

95 ** include additional rows if needed*

96 4(vii): Disclosure by Asset Category

97 ($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
99		**Total opening RAB value**	6,697	7,455	27,709	97,766	50,187	28,711	7,644	5,320	10,710	242,199
100	*less*	Total depreciation	328	206	1,174	3,515	1,638	1,410	289	584	296	9,439
101	*plus*	Total revaluations	39	44	163	574	294	168	45	31	63	1,421
102	*plus*	Assets commissioned	1,370	2,602	6,245	6,763	523	1,216	67	527	38	19,351
103	*less*	Asset disposals	–	–	–	–	–	–	–	–	–	–
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	7,778	9,894	32,943	101,588	49,367	28,685	7,467	5,294	10,515	253,531
108												
109		**Asset Life**										
110		Weighted average remaining asset life	30.5	39.6	31.6	38.3	35.2	29.9	29.3	10.2	24.2	(years)
111		Weighted average expected total asset life	56.8	59.0	45.4	58.9	46.3	45.0	37.0	22.5	29.5	(years)

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

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**		22,176	
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	77		*
12		Amortisation of initial differences in asset values	4,536		
13		Amortisation of revaluations	693		
14				5,306	
15					
16	*less*	Total revaluations	1,421		
17		Income included in regulatory profit / (loss) before tax but not taxable			*
18		Discretionary discounts and customer rebates	4,204		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax			*
20		Notional deductible interest	5,358		
21				10,983	
22					
23		**Regulatory taxable income**		16,499	
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income		16,499	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		4,620	
30					
31	* Workings to be provided in Schedule 14				
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	123,751		
37	*less*	Amortisation of initial differences in asset values	4,536		
38	*plus*	Adjustment for unamortised initial differences in assets acquired			
39	*less*	Adjustment for unamortised initial differences in assets disposed			
40		Closing unamortised initial differences in asset values		119,215	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		27	
43					

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

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				
44	**5a(iv): Amortisation of Revaluations**			**($000)**
45				
46		Opening sum of RAB values without revaluations	225,918	
47				
48		Adjusted depreciation	8,746	
49		Total depreciation	9,439	
50		Amortisation of revaluations		693
51				
52	**5a(v): Reconciliation of Tax Losses**			**($000)**
53				
54		**Opening tax losses**		
55	*plus*	Current period tax losses		
56	*less*	Utilised tax losses		
57		**Closing tax losses**		–
58	**5a(vi): Calculation of Deferred Tax Balance**			**($000)**
59				
60		**Opening deferred tax**	(4,676)	
61				
62	*plus*	Tax effect of adjusted depreciation	2,449	
63				
64	*less*	Tax effect of tax depreciation	2,227	
65				
66	*plus*	Tax effect of other temporary differences*	(99)	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	1,270	
69				
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year		
71				
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	–	
73				
74	*plus*	Deferred tax cost allocation adjustment	(0)	
75				
76		**Closing deferred tax**		(5,823)
77				
78	**5a(vii): Disclosure of Temporary Differences**			
79		*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).*		
80				
81	**5a(viii): Regulatory Tax Asset Base Roll-Forward**			
82				**($000)**
83		**Opening sum of regulatory tax asset values**	86,344	
84	*less*	Tax depreciation	7,952	
85	*plus*	Regulatory tax asset value of assets commissioned	19,488	
86	*less*	Regulatory tax asset value of asset disposals		
87	*plus*	Lost and found assets adjustment		
88	*plus*	Adjustment resulting from asset allocation		
89	*plus*	Other adjustments to the RAB tax value		
90		**Closing sum of regulatory tax asset values**		97,880

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

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

sch ref

		($000)
7	**5b(i): Summary—Related Party Transactions**	
8	Total regulatory income	
9	Operational expenditure	9,256
10	Capital expenditure	13,169
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 Divison	Divison 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	7,823	ID clause 2.3.6(1)(c)(i)
24	Northpower Contracting Division	Opex	Management Fee	1,433	ID clause 2.3.6(1)(c)(i)
25	Northpower Contracting Division	Capex	Construction of Distribution System Assets	13,169	IM clause 2.2.11(5)(b)(i)
26		[Select one]			[Select one]
27		[Select one]			[Select one]
28		[Select one]			[Select one]
29		[Select one]			[Select one]
30		[Select one]			[Select one]
31		[Select one]			[Select one]
32		[Select one]			[Select one]
33		[Select one]			[Select one]
34		[Select one]			[Select one]
35		[Select one]			[Select one]
36		[Select one]			[Select one]
37		[Select one]			[Select one]

38 ** include additional rows if needed*

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

This schedule is only to be completed if, as at the date of the most recently published financial statements, the weighted average original tenor of the debt portfolio (both qualifying debt and non-qualifying debt) is greater than five years.

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

sch ref

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

19

sch ref			
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 2016**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref						
7	**5d(i): Operating Cost Allocations**					
8		**Value allocated ($000s)**				
9		**Arm's length deduction**	**Electricity distribution services**	**Non-electricity distribution services**	**Total**	**OVABAA allocation increase ($000s)**
10	**Service interruptions and emergencies**					
11	Directly attributable		1,997			
12	Not directly attributable				–	
13	**Total attributable to regulated service**		1,997			
14	**Vegetation management**					
15	Directly attributable		2,120			
16	Not directly attributable				–	
17	**Total attributable to regulated service**		2,120			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		2,232			
20	Not directly attributable				–	
21	**Total attributable to regulated service**		2,232			
22	**Asset replacement and renewal**					
23	Directly attributable		2,495			
24	Not directly attributable				–	
25	**Total attributable to regulated service**		2,495			
26	**System operations and network support**					
27	Directly attributable		2,409			
28	Not directly attributable				–	
29	**Total attributable to regulated service**		2,409			
30	**Business support**					
31	Directly attributable		2,653			
32	Not directly attributable		1,764	11,022	12,786	
33	**Total attributable to regulated service**		4,417			
34						
35	**Operating costs directly attributable**		13,906			
36	**Operating costs not directly attributable**	–	1,764	11,022	12,786	–
37	**Operational expenditure**		15,670			
38						

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

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

sch ref		($000)
40	**Pass through and recoverable costs**	
41	**Pass through costs**	
42	Directly attributable	287
43	Not directly attributable	
44	**Total attributable to regulated service**	287
45	**Recoverable costs**	
46	Directly attributable	19,757
47	Not directly attributable	
48	**Total attributable to regulated service**	19,757
49		

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

sch ref				CY-1 ($000)	Current Year (CY) ($000)
52	**Change in cost allocation 1**				
53	Cost category		Original allocation		
54	Original allocator or line items		New allocation		
55	New allocator or line items		Difference	–	–
56					
57	Rationale for change				
58					
59					
61	**Change in cost allocation 2**				
62	Cost category		Original allocation		
63	Original allocator or line items		New allocation		
64	New allocator or line items		Difference	–	–
65					
66	Rationale for change				
67					
68					
70	**Change in cost allocation 3**				
71	Cost category		Original allocation		
72	Original allocator or line items		New allocation		
73	New allocator or line items		Difference	–	–
74					
75	Rationale for change				
76					
77					

78 ** 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.*
79 *† include additional rows if needed*

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

This schedule requires information on the allocation of asset values. This information supports the calculation of the RAB value in Schedule 4.

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	7,421
Not directly attributable	357
Total attributable to regulated service	7,778
Subtransmission cables	
Directly attributable	9,894
Not directly attributable	–
Total attributable to regulated service	9,894
Zone substations	
Directly attributable	32,943
Not directly attributable	
Total attributable to regulated service	32,943
Distribution and LV lines	
Directly attributable	98,085
Not directly attributable	3,504
Total attributable to regulated service	101,588
Distribution and LV cables	
Directly attributable	49,159
Not directly attributable	208
Total attributable to regulated service	49,367
Distribution substations and transformers	
Directly attributable	28,685
Not directly attributable	
Total attributable to regulated service	28,685
Distribution switchgear	
Directly attributable	7,467
Not directly attributable	–
Total attributable to regulated service	7,467
Other network assets	
Directly attributable	5,294
Not directly attributable	–
Total attributable to regulated service	5,294
Non-network assets	
Directly attributable	10,515
Not directly attributable	–
Total attributable to regulated service	10,515
Regulated service asset value directly attributable	249,463
Regulated service asset value not directly attributable	4,069
Total closing RAB value	253,531

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

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

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

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

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

† include additional rows if needed

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

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

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

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

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

sch ref			
7	**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8	Consumer connection		3,033
9	System growth		3,546
10	Asset replacement and renewal		10,253
11	Asset relocations		149
12	Reliability, safety and environment:		
13	Quality of supply	355	
14	Legislative and regulatory	–	
15	Other reliability, safety and environment	190	
16	**Total reliability, safety and environment**		545
17	**Expenditure on network assets**		17,526
18	Expenditure on non-network assets		236
19			
20	**Expenditure on assets**		17,762
21	*plus* Cost of financing		–
22	*less* Value of capital contributions		1,977
23	*plus* Value of vested assets		419
24			
25	**Capital expenditure**		16,204
26	**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27	Energy efficiency and demand side management, reduction of energy losses		
28	Overhead to underground conversion		
29	Research and development		
30	**6a(iii): Consumer Connection**		
31	*Consumer types defined by EDB**	**($000)**	**($000)**
32	All customer types	3,033	
33	[EDB consumer type]		
34	[EDB consumer type]		
35	[EDB consumer type]		
36	[EDB consumer type]		
37	** include additional rows if needed*		
38	**Consumer connection expenditure**		3,033
39			
40	*less* Capital contributions funding consumer connection expenditure	1,977	
41	**Consumer connection less capital contributions**		1,056
42	**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement**
43		**System Growth**	**and Renewal**
44		**($000)**	**($000)**
45	Subtransmission	1,370	2,794
46	Zone substations	2,117	1,147
47	Distribution and LV lines	10	5,648
48	Distribution and LV cables		241
49	Distribution substations and transformers		391
50	Distribution switchgear	49	32
51	Other network assets	–	
52	**System growth and asset replacement and renewal expenditure**	3,546	10,253
53	*less* Capital contributions funding system growth and asset replacement and renewal		
54	**System growth and asset replacement and renewal less capital contributions**	3,546	10,253
55			
56	**6a(v): Asset Relocations**		
57	*Project or programme**	**($000)**	**($000)**
58	Overhead line relocation Western Hills Drive (SH1) road widening	79	
59	Overhead line relocation minor works	70	
60	[Description of material project or programme]		
61	[Description of material project or programme]		
62	[Description of material project or programme]		
63	** include additional rows if needed*		
64	All other projects or programmes - asset relocations		
65	**Asset relocations expenditure**		149
66	*less* Capital contributions funding asset relocations		
67	**Asset relocations less capital contributions**		149

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

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

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
68				
69	**6a(vi): Quality of Supply**			
70		*Project or programme**	**($000)**	**($000)**
71		Comms for remote control	115	
72		11kV feeder backstopping	6	
73		Minor capex (improvements)	105	
74		Fault passage indicators	12	
75		Dargaville feeder rationalisation	117	
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply		
78	**Quality of supply expenditure**			355
79	*less*	Capital contributions funding quality of supply		
80	**Quality of supply less capital contributions**			355
81	**6a(vii): Legislative and Regulatory**			
82		*Project or programme**	**($000)**	**($000)**
83		[Description of material project or programme]		
84		[Description of material project or programme]		
85		[Description of material project or programme]		
86		[Description of material project or programme]		
87		[Description of material project or programme]		
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory		
90	**Legislative and regulatory expenditure**			–
91	*less*	Capital contributions funding legislative and regulatory		
92	**Legislative and regulatory less capital contributions**			–
93	**6a(viii): Other Reliability, Safety and Environment**			
94		*Project or programme**	**($000)**	**($000)**
95		Security improvements	4	
96		Network strategic spare store	25	
97		Backup control centre	8	
98		Research and development	59	
99		Communications and SCADA upgrades	94	
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment		
102	**Other reliability, safety and environment expenditure**			190
103	*less*	Capital contributions funding other reliability, safety and environment		
104	**Other reliability, safety and environment less capital contributions**			190
105				
106	**6a(ix): Non-Network Assets**			
107	**Routine expenditure**			
108		*Project or programme**	**($000)**	**($000)**
109		Motor vehicle	38	
110		Land	198	
111		[Description of material project or programme]		
112		[Description of material project or programme]		
113		[Description of material project or programme]		
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116	**Routine expenditure**			236
117	**Atypical expenditure**			
118		*Project or programme**	**($000)**	**($000)**
119				
120				
121				
122				
123				
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure		
126	**Atypical expenditure**			–
127				
128	**Expenditure on non-network assets**			236

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

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

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

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	1,997	
9	Vegetation management	2,120	
10	Routine and corrective maintenance and inspection	2,232	
11	Asset replacement and renewal	2,495	
12	**Network opex**		8,844
13	System operations and network support	2,409	
14	Business support	4,417	
15	**Non-network opex**		6,826
16			
17	**Operational expenditure**		15,670
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		36
22	Insurance		39
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

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

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	64,050	65,615	2%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	780	3,033	289%
11	System growth	268	3,546	1,223%
12	Asset replacement and renewal	8,305	10,253	23%
13	Asset relocations	187	149	(20%)
14	Reliability, safety and environment:			
15	Quality of supply	789	355	(55%)
16	Legislative and regulatory	400	–	(100%)
17	Other reliability, safety and environment	1,249	190	(85%)
18	**Total reliability, safety and environment**	2,438	545	(78%)
19	**Expenditure on network assets**	11,978	17,526	46%
20	Expenditure on non-network assets	113	236	109%
21	Expenditure on assets	12,091	17,762	47%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,461	1,997	37%
24	Vegetation management	1,751	2,120	21%
25	Routine and corrective maintenance and inspection	2,259	2,232	(1%)
26	Asset replacement and renewal	1,769	2,495	41%
27	**Network opex**	7,240	8,844	22%
28	System operations and network support	2,636	2,409	(9%)
29	Business support	5,504	4,417	(20%)
30	**Non-network opex**	8,140	6,826	(16%)
31	**Operational expenditure**	15,380	15,670	2%
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	52	–	(100%)
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	50	36	(28%)
41	Insurance	120	39	(68%)
42				

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

44 *2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**
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(i): Billed Quantities by Price Component

Billed quantities by price component

				Price component	Mass Market Daily Supply Charge	Mass Market Variable Charge	Commercial and Industrial Monthly charge	Commercial and Industrial Demand charge	Very Large Industrial Distribution component	Very Large Industrial Transmision Component
Consumer group name or price category code	**Consumer type or types (eg, residential, commercial etc.)**	**Standard or non-standard consumer group (specify)**	**Average no. of ICPs in disclosure year**	**Energy delivered to ICPs in disclosure year (MWh)** / **Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)**	ICP days	MWh	$/ month	kVA demand	Asset based	Relevant portion of GXP connection charge
Mass Market	Consuption based	Standard	57,165	453,034	20,358,214	453,034				
Commercial and Industrial	Demand based	Standard	76	84,566			Price Plan ND9	Price Plan ND9		
Very large industrial	Asset based	Non-standard	6	491,249					Contract	Calculation
		[Select one]								
		[Select one]								
		[Select one]								
		[Select one]								
		[Select one]								
		[Select one]								
		[Select one]								
		Standard consumer totals	57,241	537,600	20,358,214	453,034	–	–	–	–
		Non-standard consumer totals	6	491,249	–	–	–	–	–	–
		Total for all consumers	57,247	1,028,849	20,358,214	453,034	–	–	–	–

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

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

Company Name	Northpower Limited
For Year Ended	31 March 2016
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.

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

								Line charge revenues ($000) by price component					
							Price component	Mass Market Daily Supply Charge	Mass Market Variable Charge	Commercial and Industrial Monthly charge	Commercial and Industrial Demand charge	Very Large Industrial Distribution component	Very Large Industrial Transmision Component
Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Rate (eg, $ per day, $ per kWh, etc.)	$/ day	$/ kWh	$/ month	$/ kVA/ month	$/ month	$/ kW/ month
Mass Market	Consumption based	Standard	$52,694		$52,694			$6,541	$46,153				
Commercial and Industrial	Demand based	Standard	$4,122		$4,122					$88	$4,034		
Very Large Industrial	Asset based	Non-standard	$8,798		$8,798							$1,856	$6,942
		[Select one]	–										
		[Select one]	–										
		[Select one]	–										
		[Select one]	–										
		[Select one]	–										
		[Select one]	–										
		[Select one]	–										
Add extra rows for additional consumer groups or price category codes as necessary													
		Standard consumer totals	$56,817	–	$56,817	–		$6,541	$46,153	$88	$4,034	–	–
		Non-standard consumer totals	$8,798	–	$8,798	–		–	–	–	–	$1,856	$6,942
		Total for all consumers	$65,615	–	$65,615	–		$6,541	$46,153	$88	$4,034	$1,856	$6,942

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

Check: OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end: 4

Company Name **Northpower Limited**
For Year Ended **31 March 2016**
Network / Sub-network Name

SCHEDULE 9a: ASSET REGISTER

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

sch ref	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	52,719	52,670	(49)	4
10	All	Overhead Line	Wood poles	No.	1,597	1,591	(6)	2
11	All	Overhead Line	Other pole types	No.	3	2	(1)	4
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	293	293	0	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	28	28	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	10	10	0	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	8	8	0	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	3	3	0	4
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	0	0	4
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	4
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	4
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	4
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	1	1	–	4
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	21	21	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	2	2	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	6	6	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	9	9	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	169	171	2	3
29	HV	Zone substation switchgear	33kV RMU	No.	4	4	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	27	30	3	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	59	59	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	146	146	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	46	42	(4)	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3,498	3,496	(2)	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	4
37	HV	Distribution Line	SWER conductor	km	–	–	–	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	215	217	2	3
39	HV	Distribution Cable	Distribution UG PILC	km	35	38	3	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	2	2	–	1
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	31	29	(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.	8,209	8,246	37	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	29	29	–	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	177	186	9	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	5,779	5,810	31	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,336	1,351	15	4
48	HV	Distribution Transformer	Voltage regulators	No.	4	4	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	117	116	(1)	4
50	LV	LV Line	LV OH Conductor	km	1,202	1,194	(8)	2
51	LV	LV Cable	LV UG Cable	km	628	648	20	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	391	396	5	3
53	LV	Connections	OH/UG consumer service connections	No.	56,485	56,950	465	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	353	355	2	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	2	2	–	4
56	All	Capacitor Banks	Capacitors including controls	No	28	27	(1)	4
57	All	Load Control	Centralised plant	Lot	6	6	–	4
58	All	Load Control	Relays	No	32,503	33,241	738	4
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	Northpower Limited
For Year Ended	31 March 2016
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

8 **Disclosure Year (year ended)** 31 March 2016

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	2015	2016	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	152	179	1,512	8,088	8,551	9,563	7,436	582	562	493	731	798	924	1,616	1,527	1,669	1,177	880	768	756	689	670	751	139	2,457	52,670	2,457	4
11	All	Overhead Line	Wood poles	No.	1	–	22	157	224	248	286	7	23	25	44	63	35	49	58	60	39	22	20	3	11	12	66	67	49	1,591	49	2
12	All	Overhead Line	Other pole types	No.	–	–	1	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	4
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	72	104	26	38	45	4	0	0	1	0	–	–	0	0	0	0	–	1	0	–	–	–	0	293	0	4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	28	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	28	–	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	0	0	1	3	0	0	–	0	0	0	–	3	0	–	0	–	2	0	–	0	10	0	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	5	3	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	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	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	0	–	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.	–	–	–	1	–	1	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	2	–	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.	4	–	9	42	8	25	2	6	4	7	–	2	29	5	3	8	5	2	–	3	4	2	–	–	1	171	1	3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	2	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4	–	4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	19	1	–	1	1	–	–	–	–	1	–	3	2	–	–	–	2	–	–	–	30	–	4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	1	4	3	6	23	6	–	–	–	5	–	–	3	–	2	–	1	1	2	2	–	–	–	59	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	1	16	28	20	1	–	5	–	4	–	–	3	7	19	11	20	9	–	1	–	1	–	–	146	–	4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	2	1	5	5	1	3	1	2	1	–	–	8	3	1	5	–	–	–	1	–	3	–	–	42	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	14	22	118	603	814	667	433	50	21	54	33	69	37	24	26	25	23	30	50	76	87	38	51	12	119	3,496	119	3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	2	0	10	26	6	7	12	9	16	23	27	21	8	12	5	4	4	8	5	6	2	5	217	5	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	5	9	11	5	0	1	–	0	0	0	0	–	0	0	0	0	0	0	–	0	0	6	38	6	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	1
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	–	–	–	1	–	–	–	9	–	2	2	3	1	–	4	3	2	2	–	–	29	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	11	12	18	216	387	702	1,241	159	159	169	175	196	256	202	235	352	538	389	505	448	430	438	436	96	476	8,246	476	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	12	6	–	–	–	2	–	1	7	–	–	–	–	–	–	–	–	–	–	–	1	29	1	4
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	–	3	11	2	4	3	1	7	37	27	6	11	32	4	1	9	9	6	12	–	1	186	1	4
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	115	169	170	680	568	482	1,221	183	140	162	139	183	161	166	217	126	146	48	142	94	144	219	111	5	19	5,810	19	4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	3	4	17	184	182	170	154	37	37	41	29	58	84	90	70	26	37	49	3	1	14	31	28	–	2	1,351	2	4
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	2	–	–	–	–	1	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	4	–	4
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	1	14	20	20	32	6	1	7	1	1	–	–	1	4	2	2	2	2	–	–	–	–	–	116	–	4
51	LV	LV Line	LV OH Conductor	km	2	3	30	180	197	211	170	10	9	11	25	24	22	16	14	13	18	17	25	21	14	15	12	3	131	1,194	131	2
52	LV	LV Cable	LV UG Cable	km	0	–	0	25	52	52	77	15	19	25	35	49	52	51	49	26	29	15	7	6	17	9	16	4	19	648	19	3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	1	36	38	31	45	1	4	2	3	7	10	12	11	6	12	1	4	1	2	5	4	0	161	396	161	3
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	4	7	12,036	24,998	3,952	838	899	1,132	1,135	1,193	1,116	1,065	863	782	747	595	637	637	624	841	215	2,634	56,950	2,857	4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	1	–	45	85	13	6	3	3	9	19	17	25	36	24	31	2	9	1	5	–	–	21	355	21	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	2	–	4
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	5	–	1	–	–	–	3	–	–	1	5	8	–	3	–	–	–	1	–	27	–	4
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	2	–	–	–	–	1	–	–	–	2	–	–	1	–	–	–	–	–	–	–	6	–	4
59	All	Load Control	Relays	No	–	–	–	–	–	5,138	6,783	1,104	841	845	3,150	5,128	1,103	831	997	1,190	712	870	574	471	859	772	872	58	943	33,241	943	4
60	All	Civils	Cable Tunnels	km																										–		N/A

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	28	0	28
12	50kV & 66kV	75	0	75
13	33kV	218	22	241
14	SWER (all SWER voltages)			–
15	22kV (other than SWER)			–
16	6.6kV to 11kV (inclusive—other than SWER)	3,496	257	3,752
17	Low voltage (< 1kV)	1,194	648	1,843
18	**Total circuit length (for supply)**	5,011	928	5,939
19				
20	Dedicated street lighting circuit length (km)	177	219	396
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	675	13%	
25	Rural	4,336	87%	
26	Remote only		–	
27	Rugged only		–	
28	Remote and rugged		–	
29	Unallocated overhead lines		–	
30	**Total overhead length**	5,011	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	3,407	57%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	3,817	76%	

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

	Location *	Number of ICPs served	Line charge revenue ($000)
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

26 ** Extend embedded distribution networks table as necessary to disclose each embedded network owned by the EDB which is embedded in another EDB's network or in another embedded network*

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
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 new ICP's	904	
12		Commercial and Industrial new ICP's	–	
13		Very large Industrial new ICP's	–	
14		[EDB consumer type]		
15		[EDB consumer type]		
16		** include additional rows if needed*		
17		**Connections total**	904	
18				
19		**Distributed generation**		
20		Number of connections made in year	174	**connections**
21		Capacity of distributed generation installed in year	0.67	**MVA**
22		**9e(ii): System Demand**		
23				
24				
25		**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
26		GXP demand	150	
27	*plus*	Distributed generation output at HV and above	13	
28		**Maximum coincident system demand**	163	
29	*less*	Net transfers to (from) other EDBs at HV and above		
30		**Demand on system for supply to consumers' connection points**	163	
31		**Electricity volumes carried**	**Energy (GWh)**	
32		Electricity supplied from GXPs	1,046	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	22	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36		**Electricity entering system for supply to consumers' connection points**	1,068	
37	*less*	Total energy delivered to ICPs	1,029	
38		**Electricity losses (loss ratio)**	39	3.7%
39				
40		**Load factor**	0.75	
41		**9e(iii): Transformer Capacity**		
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	536	
44		Distribution transformer capacity (Non-EDB owned, estimated)	5	
45		**Total distribution transformer capacity**	541	
46				
47		**Zone substation transformer capacity**	314	

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref			
8	**10(i): Interruptions**		
9	**Interruptions by class**	**Number of interruptions**	
10	Class A (planned interruptions by Transpower)		
11	Class B (planned interruptions on the network)	406	
12	Class C (unplanned interruptions on the network)	269	
13	Class D (unplanned interruptions by Transpower)		
14	Class E (unplanned interruptions of EDB owned generation)		
15	Class F (unplanned interruptions of generation owned by others)		
16	Class G (unplanned interruptions caused by another disclosing entity)		
17	Class H (planned interruptions caused by another disclosing entity)		
18	Class I (interruptions caused by parties not included above)		
19	**Total**	675	
20			
21	**Interruption restoration**	**≤3Hrs**	**>3hrs**
22	Class C interruptions restored within	208	61
23			
24	**SAIFI and SAIDI by class**	**SAIFI**	**SAIDI**
25	Class A (planned interruptions by Transpower)		
26	Class B (planned interruptions on the network)	0.27	66.5
27	Class C (unplanned interruptions on the network)	1.89	67.3
28	Class D (unplanned interruptions by Transpower)		
29	Class E (unplanned interruptions of EDB owned generation)		
30	Class F (unplanned interruptions of generation owned by others)		
31	Class G (unplanned interruptions caused by another disclosing entity)		
32	Class H (planned interruptions caused by another disclosing entity)		
33	Class I (interruptions caused by parties not included above)		
34	**Total**	2.16	133.8
35			
36	**Normalised SAIFI and SAIDI**	**Normalised SAIFI**	**Normalised SAIDI**
37	Classes B & C (interruptions on the network)	2.15	132.9
38			
39	**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*		

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

42 ### 10(ii): Class C Interruptions and Duration by Cause

	Cause	SAIFI	SAIDI
44	**Cause**	**SAIFI**	**SAIDI**
45	Lightning	0.04	0.3
46	Vegetation	0.23	14.8
47	Adverse weather	0.20	10.6
48	Adverse environment		
49	Third party interference	0.31	15.0
50	Wildlife	0.16	6.4
51	Human error	0.01	0.2
52	Defective equipment	0.36	13.0
53	Cause unknown	0.58	6.9

55 ### 10(iii): Class B Interruptions and Duration by Main Equipment Involved

	Main equipment involved	SAIFI	SAIDI
57	**Main equipment involved**	**SAIFI**	**SAIDI**
58	Subtransmission lines		
59	Subtransmission cables		
60	Subtransmission other		
61	Distribution lines (excluding LV)		
62	Distribution cables (excluding LV)	0.01	2.1
63	Distribution other (excluding LV)	0.25	64.4

64 ### 10(iv): Class C Interruptions and Duration by Main Equipment Involved

	Main equipment involved	SAIFI	SAIDI
66	**Main equipment involved**	**SAIFI**	**SAIDI**
67	Subtransmission lines	0.30	2.3
68	Subtransmission cables		
69	Subtransmission other		
70	Distribution lines (excluding LV)	1.54	62.0
71	Distribution cables (excluding LV)	0.05	3.0
72	Distribution other (excluding LV)		

73 ### 10(v): Fault Rate

	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
74	**Main equipment involved**	**Number of Faults**	**Circuit length (km)**	**Fault rate (faults per 100km)**
75	Subtransmission lines	8	293	2.73
76	Subtransmission cables		22	–
77	Subtransmission other			
78	Distribution lines (excluding LV)	252	3,496	7.21
79	Distribution cables (excluding LV)	9	257	3.50
80	Distribution other (excluding LV)			
81	**Total**	269		

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

Company Name	Northpower Limited
Disclosure Date	
Disclosure Year (year ended)	31 March 2016

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

Table of Contents

Schedule	Description
5f	Report Supporting Cost Allocations
5g	Report Supporting Asset Allocations

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

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 2016

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	3.45%	96.55%		80	2,245	2,325	
51		Information Technology	ABAA	Number of terminal	Proxy	7.46%	92.54%		396	4,909	5,305	
52		Finance	ABAA	Revenue	Proxy	24.49%	75.51%		305	942	1,247	
		Rent	ABAA	Floor space	Causal	29.50%	70.50%		150	359	510	
53		Corporate/ Executive Board	ABAA	Revenue	Proxy	24.49%	75.51%		832	2,567	3,399	
54	**Not directly attributable**							-	1,764	11,022	12,786	-
55												
56	**Operating costs not directly attributable**							-	1,764	11,022	12,786	-
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 2016**

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%			357		357	
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**						-	357	-	357	-
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%			3,504		3,504	
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**						-	3,504	-	3,504	-
36	**Distribution and LV cables**										
37	Ducts and civils	ACAM	Allocator 1	[Select one]	100.00%			208		208	
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**						-	208	-	208	-

Company Name	**Northpower Limited**
For Year Ended	**31 March 2016**

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**							-	4,069	-	4,069	-

** include additional rows if needed*

Company Name	Northpower Ltd
For Year Ended	31 March 2016

Schedule 14 Mandatory Explanatory Notes

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 subclauses 2.5.1(1)(f),and 2.5.2(1)(e).

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 subclause 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 6.67% and 7.31%, 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 regulated income (other than gains / (losses) on asset disposals), as disclosed in 3(i) of Schedule 3

   5.2 information on reclassified items in accordance with subclause 2.7.1(2).

Box 2: Explanatory comment on regulatory profit

Other regulatory line income amounting to $293k relates to value added work on charged to customers.

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 subclause 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 subclause 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.
- FY16 additions include the purchase of assets from Transpower.

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

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

Box 6: 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 subclause 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 which were provided in accordance with formal 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 subclause 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 subclause 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 values 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 IMs.

Capital Expenditure for the Disclosure Year (Schedule 6a)

13. In the box below, comment on expenditure on assets 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 subclause 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 operational expenditure, as reported in 6b(i) of Schedule 6b;

    14.2 Information on reclassified items in accordance with subclause 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 subclause 2.7.1(2).

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

- Overall, actual capital expenditure on network assets was 46% higher than the target capital expenditure. Consumer connections expenditure was higher than forecast due to an upsurge in the number of new subdivisions during FY16. Reliability, safety and environment costs was lower in FY 16 due to timing (or deferral) of implementation of the relevant projects planned for the year. System growth of 1223% was due to the growth in the zone substation and sub transmission area.

- Overall, actual network operating expenditure was 22% higher to target due to an increased spend on service interruptions and emergencies, asset replacement and renewal and vegetation management. This was a result of poor weather conditions and a couple of major transformer malfunctions.

Information relating to revenues 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 clause 2.4.1 and subclause 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 (2%) 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 2.16 interruptions per customer. The target for planned SAIDI of 55 minutes was not achieved and the result of 67 minutes was largely due to the amount and nature of asset-replacement work on the network. Unplanned SAIDI target of 90 minutes was achieved with a result of 67 minutes. This was mainly due to more favourable winter weather conditions than had been experienced in previous years.

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.

Amendments to previously disclosed information

19. In the box below, provide information about amendments to previously disclosed information disclosed in accordance with clause 2.12.1 in the last 7 years, including:

    19.1 a description of each error; and

    19.2 for each error, reference to the web address where the disclosure made in accordance with clause 2.12.1 is publicly disclosed.

Box 16: Disclosure of amendment to previously disclosed information
None to report

Company Name	Northpower Ltd
For Year Ended	31 March 2016

Schedule 14a Mandatory Explanatory Notes on Forecast Information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

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 current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts
Future expenditures have been escalated at a rate of 2% per annum in accordance with published NZ government CPI forecasts.

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 current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts
Future expenditures have been escalated at a rate of 2% per annum in accordance with published NZ government CPI forecasts.

Company Name	Northpower Ltd
For Year Ended	31 March 2016

Schedule 15 Voluntary Explanatory Notes

1. This schedule enables 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 and 2.5.2;

   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
In disclosing our target revenue in Schedule 7(i),we note that the section in the Northpower pricing methodology that is noted in Appendix 2 as meeting the requirement of clause 2.4.3(3) of the ID Determination (section 9.6) actually represents past revenue information rather than target revenue figures. This then results in a situation where there is no previously disclosed value to use when completing cell H8 of Schedule 7(i). We have therefore used the budgeted revenue figure as approved by the Board in cell H8 of Schedule 7(i).

Independent Assurance 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, Leon Pieterse, using the staff and resources of Audit New Zealand, to provide an opinion, on her behalf, on whether the information disclosed in Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the system average interruption duration index ("SAIDI") and system average interruption frequency index ("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 2016, 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.

Our 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 (Revised) 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. Copies of these standards are available on the External Reporting Board's website.

These standards require that we comply with ethical requirements and plan and perform our assurance engagement to provide reasonable assurance about whether the Disclosure Information has been prepared in all material respects in accordance with the Determination.

We have performed procedures to obtain evidence about the amounts and disclosures in the Disclosure Information. The procedures selected depend on our 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, we considered internal control relevant to the company's preparation of the Disclosure Information in order to design 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.

We also evaluated:

- 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 assurance report has been prepared solely for the directors of the company and for the Commerce Commission for the purpose of providing those parties with reasonable 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 a reasonable assurance 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 assurance report has been formed on the above basis.

Independence and quality control

When carrying out the engagement, we complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 (Revised) issued by the New Zealand Auditing and Assurance Standards Board; and
- quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

We also complied with the independence 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;
- as far as appears from an examination, 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; and
- the Disclosure Information has been prepared, in all material respects, in accordance with the Determination.

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
24 August 2016

"safe, reliable, hassle free service"

Northpower

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Certification for Year-end Disclosures

We, Nikki Davies-Colley and Michael James, 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, 2.3.2, 2.4.21, 2.4.22, 2.5.1, 2.5.2, 2.7.1 and 2.7.3 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, 14 and 15 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.

Director	Director
24 August 2016	24 August 2016
Date	Date