COMMERCE COMMISSION NEW ZEALAND

EDB Information Disclosure Requirements
Information Templates

Schedules 1–10
excluding 5f–5h

Company Name	Northpower
Disclosure Date	31 August 2024
Disclosure Year (year ended)	31 March 2024

Templates for Schedules 1–10 excluding 5f–5h
Prepared 16 February 2024

Table of Contents

Disclosure Template Instructions

This document forms Schedules 1–10 to the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2.

The Schedules take the form of templates for use by EDBs when making disclosures under clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, and 2.5.2 of the Electricity Distribution Information Disclosure Determination 2012.

Company Name and Dates

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

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

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

Dates should be entered in day/month/year order (Example -"1 April 2023").

Data Entry Cells and Calculated Cells

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

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

Validation Settings on Data Entry Cells

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

Conditional Formatting Settings on Data Entry Cells

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

Schedule 4 cells P99:P106 and P107 will change colour if the RAB values do not equal the corresponding values in table 4(ii).

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

Schedule 9b cells in rows 10 to 60 of the column "Items at end of year (quantity)" will change colour if the total assets at year end for each asset class does not equal the corresponding values in column I in Schedule 9a.

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

Inserting Additional Rows and Columns

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

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

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

The template for schedule 8 may require additional columns to be inserted between column L and Q, and between U and AF. If inserting additional columns, headings will need to be copied into the added columns. Additionally, the formulas for standard consumers total, non-standard consumers totals and total for all consumers will need to be copied into the cells of the added columns. The column headings and formulas can be found in the equivalent cells of the existing columns.

Disclosures by Sub-Network

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

Description of Calculation References

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

Worksheet Completion Sequence

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

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

Company Name **Northpower**
For Year Ended **31 March 2024**

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 this ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of this determination.
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7 1(i): Expenditure metrics

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)
8						
9	**Operational expenditure**	45,729	567	229,561	5,821	59,430
10	Network	20,174	250	101,273	2,568	26,218
11	Non-network	25,555	317	128,289	3,253	33,212
12						
13	**Expenditure on assets**	55,105	684	276,628	7,014	71,614
14	Network	53,395	663	268,044	6,797	69,392
15	Non-network	1,710	21	8,584	218	2,222
16						

17 1(ii): Revenue metrics

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
18			
19	**Total consumer line charge revenue**	89,692	1,113
20	Standard consumer line charge revenue	75,917	942
21	Non-standard consumer line charge revenue	13,776	1,362,843
22			

23 1(iii): Service intensity measures

sch ref			
24			
25	Demand density	25	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	127	*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	12,409	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

30 1(iv): Composition of regulatory income

sch ref		($000)	% of revenue
31			
32	Operational expenditure	36,193	48.97%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	18,689	25.29%
34	Total depreciation	13,043	17.65%
35	Total revaluations	14,140	19.13%
36	Regulatory tax allowance	1,503	2.03%
37	Regulatory profit/(loss) including financial incentives and wash-ups	18,624	25.20%
38	**Total regulatory income**	73,911	
39			

40 1(v): Reliability

sch ref			
41			
42	Interruption rate	16.02	*Interruptions per 100 circuit km*

Company Name	**Northpower**
For Year Ended	**31 March 2024**

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 this 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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

2(i): Return on Investment

	CY-2	CY-1	Current Year CY
ROI – comparable to a post tax WACC	%	%	%
Reflecting all revenue earned	8.46%	5.91%	4.62%
Excluding revenue earned from financial incentives	8.46%	5.91%	4.62%
Excluding revenue earned from financial incentives and wash-ups	8.46%	5.91%	4.62%
Mid-point estimate of post tax WACC	3.52%	4.88%	6.05%
25th percentile estimate	2.84%	4.20%	5.37%
75th percentile estimate	4.20%	5.56%	6.73%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	8.76%	6.43%	5.32%
Excluding revenue earned from financial incentives	8.76%	6.43%	5.32%
Excluding revenue earned from financial incentives and wash-ups	8.76%	6.43%	5.32%
WACC rate used to set regulatory price path			
Mid-point estimate of vanilla WACC	3.82%	5.39%	6.75%
25th percentile estimate	3.14%	4.71%	6.07%
75th percentile estimate	4.50%	6.07%	7.43%

2(ii): Information Supporting the ROI

			($000)	
	Total opening RAB value	353,169		
plus	Opening deferred tax	(15,954)		
Opening RIV			337,215	
Line charge revenue			70,987	
	Expenses cash outflow	54,881		
add	Assets commissioned	33,263		
less	Asset disposals	985		
add	Tax payments	(644)		
less	Other regulated income	2,924		
Mid-year net cash outflows			83,591	
Term credit spread differential allowance			–	
	Total closing RAB value	386,466		
less	Adjustment resulting from asset allocation	(78)		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(18,102)		
Closing RIV			368,442	
ROI – comparable to a vanilla WACC				5.32%
	Leverage (%)			42%
	Cost of debt assumption (%)			5.97%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				4.62%

Company Name	**Northpower**
For Year Ended	**31 March 2024**

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 this 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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

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

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

Year-end ROI – comparable to a vanilla WACC	5.26%
Year-end ROI – comparable to a post tax WACC	4.56%

** 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

IRIS incentive adjustment		
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		
CPP application recoverable costs		
Catastrophic event allowance		
Capex wash-up adjustment		
Transmission asset wash-up adjustment		
2013–15 NPV wash-up allowance		
Reconsideration event allowance		
Other wash-ups		
Wash-up costs		–
Impact of wash-up costs on ROI		–

Company Name	**Northpower**
For Year Ended	**31 March 2024**

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 this 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		70,987
10	*plus*	Gains / (losses) on asset disposals		
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		2,924
12				
13		**Total regulatory income**		73,911
14		**Expenses**		
15	*less*	Operational expenditure		36,193
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		18,689
18				
19		**Operating surplus / (deficit)**		19,030
20				
21	*less*	Total depreciation		13,043
22				
23	*plus*	Total revaluations		14,140
24				
25		**Regulatory profit / (loss) before tax**		20,127
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		1,503
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		18,624
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	184	
36		Commerce Act levies	76	
37		Industry levies	202	
38		CPP specified pass through costs		
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	18,226	
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		
46		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		18,689
47				
48		**3(iv): Merger and Acquisition Expenditure**		
49				**($000)**
50		Merger and acquisition expenditure		
51				
52		*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)*		
53		**3(v): Other Disclosures**		
54				**($000)**
55		Self-insurance allowance		

Company Name	Northpower
For Year Ended	31 March 2024

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 this 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)

sch ref		RAB CY-4 ($000)	RAB CY-3 ($000)	RAB CY-2 ($000)	RAB CY-1 ($000)	RAB CY ($000)
10	**Total opening RAB value**	267,167	279,361	298,438	328,448	353,169
12	*less* **Total depreciation**	9,962	10,574	11,454	12,204	13,043
14	*plus* **Total revaluations**	6,765	4,241	20,647	21,787	14,140
16	*plus* **Assets commissioned**	16,089	24,903	20,879	15,667	33,263
18	*less* **Asset disposals**	57	29	453	151	985
20	*plus* **Lost and found assets adjustment**	–	–	–	–	–
22	*plus* **Adjustment resulting from asset allocation**	(642)	536	392	(379)	(78)
24	**Total closing RAB value**	279,361	298,438	328,448	353,169	386,466

26 4(ii): Unallocated Regulatory Asset Base

sch ref		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
29	**Total opening RAB value**		355,905		353,169
30	*less*				
31	**Total depreciation**		13,170		13,043
32	*plus*				
33	**Total revaluations**		14,250		14,140
34	*plus*				
35	Assets commissioned (other than below)	6,099		6,099	
36	Assets acquired from a regulated supplier	–		–	
37	Assets acquired from a related party	27,164		27,164	
38	**Assets commissioned**		33,263		33,263
39	*less*				
40	Asset disposals (other than below)	985		985	
41	Asset disposals to a regulated supplier				
42	Asset disposals to a related party				
43	**Asset disposals**		985		985
45	*plus* **Lost and found assets adjustment**				
47	*plus* **Adjustment resulting from asset allocation**				(78)
49	**Total closing RAB value**		389,263		386,466

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**
For Year Ended	**31 March 2024**

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 this 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				1,267
55		CPI_4^{-4}				1,218
56		Revaluation rate (%)				4.02%
57						
58			**Unallocated RAB ***		**RAB**	
59			**($000)**	**($000)**	**($000)**	**($000)**
60		Total opening RAB value	355,905		353,169	
61	*less*	Opening value of fully depreciated, disposed and lost assets	1,681		1,681	
62						
63		Total opening RAB value subject to revaluation	354,224		351,488	
64		**Total revaluations**		14,250		14,140
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**		17,771		15,186
69	*plus*	Capital expenditure	32,409		32,397	
70	*less*	Assets commissioned	33,263		33,263	
71	*plus*	Adjustment resulting from asset allocation				
72		**Works under construction - current disclosure year**		16,917		14,320
73						
74		Highest rate of capitalised finance applied				6.81%
75						

Company Name	Northpower
For Year Ended	31 March 2024

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 this 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	12,454		12,332	
80	Depreciation - no standard life assets	716		711	
81	Depreciation - modified life assets				
82	Depreciation - alternative depreciation in accordance with CPP				
83	**Total depreciation**		13,170		13,043
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**	8,459	10,745	40,155	143,194	53,718	57,360	10,272	7,655	21,611	353,169
100	*less*	Total depreciation	396	331	1,516	4,847	2,032	1,993	456	761	711	13,043
101	*plus*	Total revaluations	340	432	1,604	5,733	2,162	2,305	412	283	869	14,140
102	*plus*	Assets commissioned	246	–	14,340	10,360	1,084	3,427	1,557	–	2,249	33,263
103	*less*	Asset disposals	–	–	265	–	–	52	31	636	–	985
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	(3)	–	–	(92)	17	–	–	–	–	(78)
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	8,646	10,846	54,317	154,348	54,949	61,047	11,754	6,540	24,019	386,466
108												
109		**Asset Life**										
110		Weighted average remaining asset life	33.8	37.4	33.7	42.0	31.1	34.8	27.2	15.7	27.5	(years)
111		Weighted average expected total asset life	55.1	57.5	47.4	59.7	47.7	45.0	37.7	22.6	33.1	(years)

Company Name	**Northpower**
For Year Ended	**31 March 2024**

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 this ID determination), and so is subject to the assurance report required by section

sch ref					
7		**5a(i): Regulatory Tax Allowance**		**($000)**	
8		**Regulatory profit / (loss) before tax**		20,127	
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	19		*
12		Amortisation of initial differences in asset values	4,532		
13		Amortisation of revaluations	3,044		
14				7,595	
15					
16	*less*	Total revaluations	14,140		
17		Income included in regulatory profit / (loss) before tax but not taxable			*
18		Discretionary discounts and customer rebates			
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax			*
20		Notional deductible interest	8,214		
21				22,354	
22					
23		**Regulatory taxable income**		5,369	
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income		5,369	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		1,503	
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	87,467		
37	*less*	Amortisation of initial differences in asset values	4,532		
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		82,935	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		19.3	
43					

Company Name	**Northpower**
For Year Ended	**31 March 2024**

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 this ID determination), and so is subject to the assurance report required by section

sch ref				
44	**5a(iv): Amortisation of Revaluations**			**($000)**
46		Opening sum of RAB values without revaluations	279,578	
48		Adjusted depreciation	9,999	
49		Total depreciation	13,043	
50		Amortisation of revaluations		3,044
52	**5a(v): Reconciliation of Tax Losses**			**($000)**
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)**
60		**Opening deferred tax**	(15,954)	
62	*plus*	Tax effect of adjusted depreciation	2,800	
64	*less*	Tax effect of tax depreciation	3,620	
66	*plus*	Tax effect of other temporary differences*	(167)	
68	*less*	Tax effect of amortisation of initial differences in asset values	1,269	
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year		
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	(127)	
74	*plus*	Deferred tax cost allocation adjustment	(18)	
76		**Closing deferred tax**		(18,102)
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).*		
81	**5a(viii): Regulatory Tax Asset Base Roll-Forward**			
82				**($000)**
83		**Opening sum of regulatory tax asset values**	135,974	
84	*less*	Tax depreciation	12,930	
85	*plus*	Regulatory tax asset value of assets commissioned	37,695	
86	*less*	Regulatory tax asset value of asset disposals	530	
87	*plus*	Lost and found assets adjustment		
88	*plus*	Adjustment resulting from asset allocation	(141)	
89	*plus*	Other adjustments to the RAB tax value		
90		**Closing sum of regulatory tax asset values**		160,067

Company Name	**Northpower**
For Year Ended	**31 March 2024**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with clause 2.3.6 of this ID determination.
This information is part of audited disclosure information (as defined in clause 1.4 of this ID determination), and so is subject to the assurance report required by clause 2.8.

sch ref				
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**	
8	**Total regulatory income**			
9				
10	**Market value of asset disposals**			
11				
12	Service interruptions and emergencies	3,619		
13	Vegetation management	3,171		
14	Routine and corrective maintenance and inspection	4,207		
15	Asset replacement and renewal (opex)	4,126		
16	**Network opex**		15,123	
17	Business support	43		
18	System operations and network support	285		
19	Non-network solutions provided by a related party or third party	–		*Not Required before DY2025*
20	**Operational expenditure**		15,451	
21	Consumer connection	78		
22	System growth	7,876		
23	Asset replacement and renewal (capex)	18,309		
24	Asset relocations	16		
25	Quality of supply	231		
26	Legislative and regulatory	–		
27	Other reliability, safety and environment	1,380		
28	**Expenditure on non-network assets**		37	
29	**Expenditure on assets**		27,927	
30	Cost of financing			
31	Value of capital contributions			
32	Value of vested assets			
33	**Capital Expenditure**		27,927	
34	**Total expenditure**		43,378	
35				
36	**Other related party transactions**			

37 5b(iii): Total Opex and Capex Related Party Transactions

38	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
39	Northpower Contracting Division	Service interruptions and emergencies	3,619
40	Northpower Contracting Division	Vegetation management	3,171
41	Northpower Contracting Division	Routine and corrective maintenance and inspection	4,207
42	Northpower Contracting Division	Asset replacement and renewal (opex)	4,126
43	Northpower Contracting Division	System operations and network support	199
44	Northpower Fibre Limited	System operations and network support	86
45	Electricity Engineers' Association	Business support	43
46	Northpower Contracting Division	Asset relocations	16
47	Northpower Contracting Division	Consumer connection	78
48	Northpower Contracting Division	Asset replacement and renewal (capex)	18,309
49	Northpower Contracting Division	Quality of supply	231
50	Northpower Contracting Division	Other reliability, safety and environment	1,380
51	Northpower Contracting Division	System growth	7,876
52	Northpower Contracting Division	Expenditure on non-network assets	37
53		[Select one]	
54	**Total value of related party transactions**		43,378

55 ** include additional rows if needed*

Company Name	**Northpower**
For Year Ended	**31 March 2024**

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 this 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	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	42%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

Company Name	**Northpower**
For Year Ended	**31 March 2024**

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 this 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			3,714			
12	Not directly attributable					–	
13	**Total attributable to regulated service**			3,714			
14	**Vegetation management**						
15	Directly attributable			3,633			
16	Not directly attributable					–	
17	**Total attributable to regulated service**			3,633			
18	**Routine and corrective maintenance and inspection**						
19	Directly attributable			4,259			
20	Not directly attributable					–	
21	**Total attributable to regulated service**			4,259			
22	**Asset replacement and renewal**						
23	Directly attributable			4,361			
24	Not directly attributable					–	
25	**Total attributable to regulated service**			4,361			
26	**Non-network solutions provided by a related party or third party**	*Not required before DY2025*					
27	Directly attributable						
28	Not directly attributable					–	
29	**Total attributable to regulated service**			–			
30	**System operations and network support**						
31	Directly attributable			8,819			
32	Not directly attributable					–	
33	**Total attributable to regulated service**			8,819			
34	**Business support**						
35	Directly attributable			6,098			
36	Not directly attributable			5,309	14,761	20,070	
37	**Total attributable to regulated service**			11,407			
38							
39	**Operating costs directly attributable**			30,884			
40	**Operating costs not directly attributable**		–	5,309	14,761	20,070	–
41	**Operational expenditure**			36,193			
42							

Company Name	**Northpower**
For Year Ended	**31 March 2024**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	462
Not directly attributable	
Total attributable to regulated service	462
Recoverable costs	
Directly attributable	18,226
Not directly attributable	
Total attributable to regulated service	18,226

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

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

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

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

** a change in cost allocation must be completed for each cost allocator change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or component.*
† include additional rows if needed

Company Name	**Northpower**
For Year Ended	**31 March 2024**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7 5e(i): Regulated Service Asset Values

sch ref		Value allocated ($000s) Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	8,343
12	Not directly attributable	303
13	**Total attributable to regulated service**	8,646
14	**Subtransmission cables**	
15	Directly attributable	10,846
16	Not directly attributable	
17	**Total attributable to regulated service**	10,846
18	**Zone substations**	
19	Directly attributable	54,317
20	Not directly attributable	
21	**Total attributable to regulated service**	54,317
22	**Distribution and LV lines**	
23	Directly attributable	145,722
24	Not directly attributable	8,626
25	**Total attributable to regulated service**	154,348
26	**Distribution and LV cables**	
27	Directly attributable	54,499
28	Not directly attributable	450
29	**Total attributable to regulated service**	54,949
30	**Distribution substations and transformers**	
31	Directly attributable	61,047
32	Not directly attributable	
33	**Total attributable to regulated service**	61,047
34	**Distribution switchgear**	
35	Directly attributable	11,754
36	Not directly attributable	
37	**Total attributable to regulated service**	11,754
38	**Other network assets**	
39	Directly attributable	5,477
40	Not directly attributable	1,063
41	**Total attributable to regulated service**	6,540
42	**Non-network assets**	
43	Directly attributable	20,366
44	Not directly attributable	3,653
45	**Total attributable to regulated service**	24,019
46		
47	**Regulated service asset value directly attributable**	372,371
48	**Regulated service asset value not directly attributable**	14,095
49	**Total closing RAB value**	386,466
50		

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

sch ref				($000) CY-1	Current Year (CY)
53	**Change in asset value allocation 1**				
54	Asset category		Original allocation		
55	Original allocator or line items		New allocation		
56	New allocator or line items		Difference	–	–
58	Rationale for change				
62	**Change in asset value allocation 2**				
63	Asset category		Original allocation		
64	Original allocator or line items		New allocation		
65	New allocator or line items		Difference	–	–
67	Rationale for change				
71	**Change in asset value allocation 3**				
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
76	Rationale for change				

79 ** 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.*

80 *† include additional rows if needed*

Company Name	**Northpower**
For Year Ended	**31 March 2024**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			($000)	($000)
7		**6a(i): Expenditure on Assets**		
8		Consumer connection		8,142
9		System growth		8,810
10		Asset replacement and renewal		23,208
11		Asset relocations		521
12		Reliability, safety and environment:		
13		Quality of supply	478	
14		Legislative and regulatory	214	
15		Other reliability, safety and environment	886	
16		**Total reliability, safety and environment**		1,579
17		**Expenditure on network assets**		42,260
18		Expenditure on non-network assets		1,353
19				
20		**Expenditure on assets**		43,613
21	*plus*	Cost of financing		1,371
22	*less*	Value of capital contributions		12,586
23	*plus*	Value of vested assets		
24				
25		**Capital expenditure**		32,397

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

			($000)	($000)
31		**6a(iii): Consumer Connection**		
32		*Consumer types defined by EDB**		
33		All customer types	8,142	
34				
35				
36				
37				
38		** include additional rows if needed*		
39		**Consumer connection expenditure**		8,142
40				
41	*less*	Capital contributions funding consumer connection expenditure	12,586	
42		**Consumer connection less capital contributions**		(4,445)

			System Growth ($000)	Asset Replacement and Renewal ($000)
43		**6a(iv): System Growth and Asset Replacement and Renewal**		
44				
45				
46		Subtransmission	73	1,177
47		Zone substations	7,758	8,109
48		Distribution and LV lines	852	9,503
49		Distribution and LV cables	6	1,324
50		Distribution substations and transformers	121	1,407
51		Distribution switchgear		59
52		Other network assets		1,629
53		**System growth and asset replacement and renewal expenditure**	8,810	23,208
54	*less*	Capital contributions funding system growth and asset replacement and renewal		
55		**System growth and asset replacement and renewal less capital contributions**	8,810	23,208
56				

			($000)	($000)
57		**6a(v): Asset Relocations**		
58		*Project or programme**		
59		Ground Mounted Sub	278	
60		Minor expenditure - relocations	21	
61		Overhead to underground	222	
62				
63				
64		** include additional rows if needed*		
65		All other projects or programmes - asset relocations		
66		**Asset relocations expenditure**		521
67	*less*	Capital contributions funding asset relocations		
68		**Asset relocations less capital contributions**		521

	Company Name	**Northpower**
	For Year Ended	**31 March 2024**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			($000)	($000)
69				
70	**6a(vi): Quality of Supply**			
71		*Project or programme**	($000)	($000)
72		SCADA and communications improvements	379	
73		Kensington 110kV Bus re-configuration	75	
74		Low Voltage Visability	24	
75				
76				
77		** include additional rows if needed*		
78		All other projects programmes - quality of supply		
79	**Quality of supply expenditure**			478
80	*less*	Capital contributions funding quality of supply		
81	**Quality of supply less capital contributions**			478
82	**6a(vii): Legislative and Regulatory**			
83		*Project or programme**	($000)	($000)
84		4 Block AUFLS	214	
85				
86				
87				
88				
89		** include additional rows if needed*		
90		All other projects or programmes - legislative and regulatory		
91	**Legislative and regulatory expenditure**			214
92	*less*	Capital contributions funding legislative and regulatory		
93	**Legislative and regulatory less capital contributions**			214
94	**6a(viii): Other Reliability, Safety and Environment**			
95		*Project or programme**	($000)	($000)
96		Long and Crawford GMS replacement	531	
97		Minor capital expenditure	39	
98		Ring main units	203	
99		Zone substation security improvements	49	
		Smart Distribution system	20	
100		Ruawai Transformer	44	
101		** include additional rows if needed*		
102		All other projects or programmes - other reliability, safety and environment		
103	**Other reliability, safety and environment expenditure**			886
104	*less*	Capital contributions funding other reliability, safety and environment		
105	**Other reliability, safety and environment less capital contributions**			886
106				
107	**6a(ix): Non-Network Assets**			
108	**Routine expenditure**			
109		*Project or programme**	($000)	($000)
110		Hiko	76	
111		Minor capital expenditure	32	
112		Lease Vehicles	152	
113				
114				
115		** include additional rows if needed*		
116		All other projects or programmes - routine expenditure		
117	**Routine expenditure**			261
118	**Atypical expenditure**			
119		*Project or programme**	($000)	($000)
120		ADMS CRM Outages - Salesforce Call taking and Dispatch Integration	174	
121		ADMS Data insights - Data Lake and Outage Reporting	153	
		ADMS Outages – Poweron Outage Management System	661	
		Arbourlab Integration	38	
		ESRI Geospatial Tool Sets	45	
		Faults Management System	20	
		G Tech Upgrade	3	
124				
125		** include additional rows if needed*		
126		All other projects or programmes - atypical expenditure		
127	**Atypical expenditure**			1,093
128				
129	**Expenditure on non-network assets**			1,353

	Company Name	**Northpower**
	For Year Ended	**31 March 2024**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			($000)	($000)
7	**6b(i): Operational Expenditure** *Required for DY2024 and DY2025 only*			
8	Service interruptions and emergencies		3,714	
9	Vegetation management		3,633	
10	Routine and corrective maintenance and inspection		4,259	
11	Asset replacement and renewal		4,361	
12	**Network opex**			15,967
13	Non-network solutions provided by a related party or third party	*Required for DY2025 only*		
14	System operations and network support		8,819	
15	Business support		11,407	
16	**Non-network opex**			20,226
17				
18	**Operational expenditure**			36,193
19	**6b(i): Operational Expenditure** *Not Required before DY2026*		($000)	($000)
20	Service interruptions and emergencies:			
21	Vegetation-related			
22	Other			
23	**Total service interruptions and emergencies**		–	
24	Vegetation management:			
25	Assessment and notification costs			
26	Felling or trimming vegetation - in-zone			
27	Felling or trimming vegetation - out-of-zone			
28	Other			
29	**Total vegetation management**		–	
30				
31	Routine and corrective maintenance and inspection:			
32	Asset replacement and renewal			
33	**Network opex**			–
34	Non-network solutions provided by a related party or third party			

Company Name	**Northpower**
For Year Ended	**31 March 2024**

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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref			
35	System operations and network support		
36	Business support		
37	**Non-network opex**		–
38			
39	**Operational expenditure**		–

40 **6b(ii): Subcomponents of Operational Expenditure (where known)**

41	Energy efficiency and demand side management, reduction of energy losses	
42	Direct billing*	
43	Research and development	
44	Insurance	
45	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*	

Company Name	**Northpower**
For Year Ended	

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 this 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	73,600	70,987	(4%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	5,972	8,142	36%
11	System growth	13,980	8,810	(37%)
12	Asset replacement and renewal	22,496	23,208	3%
13	Asset relocations	340	521	53%
14	Reliability, safety and environment:			
15	Quality of supply	1,774	478	(73%)
16	Legislative and regulatory	–	214	–
17	Other reliability, safety and environment	479	886	85%
18	**Total reliability, safety and environment**	2,253	1,579	(30%)
19	**Expenditure on network assets**	45,041	42,260	(6%)
20	Expenditure on non-network assets	1,516	1,353	(11%)
21	Expenditure on assets	46,557	43,613	(6%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	2,880	3,714	29%
24	Vegetation management	3,029	3,633	20%
25	Routine and corrective maintenance and inspection	4,743	4,259	(10%)
26	Asset replacement and renewal	3,135	4,361	39%
27	**Network opex**	13,787	15,967	16%
28	Non-network solutions provided by a related party or third party *Not Required before DY2025*		–	–
29	System operations and network support	4,873	8,819	81%
30	Business support	16,443	11,407	(31%)
31	**Non-network opex**	21,316	20,226	(5%)
32	**Operational expenditure**	35,103	36,193	3%
33	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
34	Energy efficiency and demand side management, reduction of energy losses		–	–
35	Overhead to underground conversion		–	–
36	Research and development		–	–
37				
38	**7(v): Subcomponents of Operational Expenditure (where known)**			
39	Energy efficiency and demand side management, reduction of energy losses		–	–
40	Direct billing		–	–
41	Research and development		–	–
42	Insurance		–	–
43				

44 *1 From the nominal dollar target revenue for the disclosure year disclosed under clause 2.4.3(3) of this determination*

45 *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
For Year Ended	31 March 2024
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.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

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

sch ref	Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
15	DM1 - Principal Res - Low User	Residential	Standard	2,972	11,710
16	User	Residential	Standard	27,087	143,240
17	DM3 - Non-Principal Residence	Residential	Standard	790	1,971
18	Residence	Residential	Standard	4,879	19,682
19	DM7 - Principal Res - Standard	Residential	Standard	1,796	12,816
20	Standard	Residential	Standard	15,029	146,549
21	less)	General	Standard	2,745	23,334
22	or less)	General	Standard	7,140	92,135
23	Metering)	General	Standard	76	4,205
24	Metering)	General	Standard	362	36,134
25	ND5 - Irrigation and Pumps	General	Standard	70	2,592
26	ND6 - Unmetered 24 Hour	General	Standard	192	300
27	Lighting	General	Standard	17	2,210
28	ND12 - Builders Supply	General	Standard	448	995
29	Based ToU	Large Commercial	Standard	46	7,849
30	Based	Large Commercial	Standard	30	20,811
31	Capacity	Large Commercial	Standard	92	66,078
	Based	Large Commercial	Standard	2	1,563
	1 MW	Large Commercial	Standard	1	1
32	IND - Individual Pricing	Asset Based	Non-standard	8	197,278
33	Discount (1 to 1,999 kWh)	All Consumers	Standard		
34	Discount (2,000+ kWh)	All Consumers	Standard		
35	*Add extra rows for additional consumer groups or price category codes as necessary*				
36			**Standard consumer totals**	63,774	594,177
37			**Non-standard consumer totals**	8	197,278
38			**Total for all consumers**	63,782	791,454

Billed quantities by price component *Not Required after DY2024*

sch ref	Consumer group name or price category code	Daily Fixed Charge	Daily Fixed Charge	Consumption	Injection	Demand (incl Excess Demand)	Capacity	Excess Reactive Power	Excess Reactive Power	Asset Utilisation	Transmission Pass Through	Eligible Discount
	Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	ICP Day	Fixture Day	kWh	kWh	kVA	kVA	kVArh	kVAr	Per ICP	Per ICP	Per ICP
15	DM1 - Principal Res - Low User	1,099,183		15,906,722	671,369							
16	User	9,838,487		143,887,103	3,097,049							
17	DM3 - Non-Principal Residence	298,148		2,717,548	76,607							
18	Residence	1,743,141		18,852,360	170,669							
19	DM7 - Principal Res - Standard	674,721		16,471,242	367,996							
20	Standard	5,396,609		137,576,008	1,810,204							
21	less)	797,522		27,971,599	43,371							
22	or less)	2,516,536		87,483,002	591,773							
23	Metering)	25,192		5,757,899	5,030							
24	Metering)	132,777		35,241,953	468,214							
25	ND5 - Irrigation and Pumps	24.224		2.592.803								
26	ND6 - Unmetered 24 Hour	70.152	1.403	318.556								
27	Lighting	–	86,776	1,957,682								
28	ND12 - Builders Supply	149,481		1,002,106								
29	Based ToU	16,836		7,849,209	71,816			3,267				
30	Based	10,723		20,811,440	10,640	50,305	76,984	4,926				
31	Capacity	33,124		65,902,138	1,795	205,471	582,646	23,755				
	Based	519		1,582,018		5,057	16,600	1,516				
	1 MW	366		786	767,187							
32	IND - Individual Pricing			197,277,819					55,539	8	8	
33	Discount (1 to 1,999 kWh)											8.430
34	Discount (2,000+ kWh)											53.137
36	**Standard consumer totals**	22,827,741	88,179	593,882,174	8,153,720	260,833	676,230	33,464	–	–	–	61,567
37	**Non-standard consumer totals**	–	–	197,277,819	–	–	–	–	55,539	8	8	–
38	**Total for all consumers**	22,827,741	88,179	791,159,993	8,153,720	260,833	676,230	33,464	55,539	8	8	61,567

Billed quantities by price component ***Not Required before DY2025***

	[Select one]		[Select one]		[Select one]		[Select one]	
Standardised price component	[Select one]		[Select one]		[Select one]		[Select one]	
EDB defined price component								
	Distribution billed quantity	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**	**Distribution billed quantity**	**Transmission billed quantity**
36	–	–	–	–	–	–	–	–
37	–	–	–	–	–	–	–	–
38	–	–	–	–	–	–	–	–

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

	Company Name	Northpower
	For Year Ended	31 March 2024
	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.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

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

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Total distribution line charge revenue *Not Required after DY2024*	Total transmission line charge revenue *Not Required after DY2024*
DM1 - Principal Res - Low User	Residential	Standard	$2,125	2,125	
User	Residential	Standard	$18,871	18,871	
DM3 - Non-Principal Residence	Residential	Standard	$673	673	
Residence	Residential	Standard	$3,920	3,920	
DM7 - Principal Res - Standard	Residential	Standard	$2,074	2,074	
Standard	Residential	Standard	$15,311	15,311	
less)	General	Standard	$4,166	4,166	
or less)	General	Standard	$13,023	13,023	
Metering)	General	Standard	$754	754	
Metering)	General	Standard	$4,476	4,476	
ND5 - Irrigation and Pumps	General	Standard	$275	275	
ND6 - Unmetered 24 Hour	General	Standard	$293	293	
Lighting	General	Standard	$667	667	
ND12 - Builders Supply	General	Standard	$282	282	
Based ToU	Large Commercial	Standard	$1,117	1,117	
Based	Large Commercial	Standard	$710	710	
Capacity	Large Commercial	Standard	$5,173	5,173	
Based	Large Commercial	Standard	$135	135	
1 MW	Large Commercial	Standard	$8	8	
IND - Individual Pricing	Asset Based	Non-standard	$10,903	10,903	
Discount (1 to 1,999 kWh)	All Consumers	Standard	($781)	(781)	
Discount (2,000+ kWh)	All Consumers	Standard	($13,188)	(13,188)	
Add extra rows for additional consumer groups or price category codes as necessary					
		Standard consumer totals	$60,085	$60,085	–
		Non-standard consumer totals	$10,903	$10,903	–
		Total for all consumers	$70,987	$70,987	–
				Check	OK

Line charge revenues ($000) by price component *Not Required after DY2024*

Price component	Daily Fixed Charge	Daily Fixed Charge	Consumption	Injection	Demand (incl Excess Demand)	Capacity	Excess Reactive Power	Excess Reactive Power	Asset Utilisation	Transmission Pass Through	Eligible Discount
Rate (eg, $ per day, $ per kWh, etc.)	$ per ICP per Day	$ Fixture per Day	$ per kWh	$ per kWh	kVA	kVA	$ per Excess kVArh	kVAr	Asset Value	Coincident kW Demand	$ per Eligibility
DM1 - Principal Res - Low User	$494		$1,624	$7							
User	$4,427		$14,412	$31							
DM3 - Non-Principal Residence	$537		$136	$1							
Residence	$3,138		$780	$2							
DM7 - Principal Res - Standard	$1,214		$856	$4							
Standard	$9,715		$5,579	$18							
less)	$1,913		$2,252	$1							
or less)	$6,040		$6,976	$6							
Metering)	$126		$628	$0							
Metering)	$664		$3,807	$5							
ND5 - Irrigation and Pumps	$58		$217								
ND6 - Unmetered 24 Hour	$105	$169	$19								
Lighting	–	$496	$171								
ND12 - Builders Supply	$224		$58								
Based ToU	$84		$1,027	$1			$5				
Based	$54			$0	$0	$648	$8				
Capacity	$166			$0	$43	$4,925	$39				
Based	$3				–	$130	$3				
1 MW				$8							
IND - Individual Pricing			$43					$84	$4,308	$6,468	
Discount (1 to 1,999 kWh)											($781)
Discount (2,000+ kWh)											($13,188)
Standard consumer totals	$28,962	$665	$38,542	$82	$43	$5,703	$55	–	–	–	($13,969)
Non-standard consumer totals	–	–	$43	–	–	–	–	$84	$4,308	$6,468	–
Total for all consumers	$28,962	$665	$38,585	$82	$43	$5,703	$55	$84	$4,308	$6,468	($13,969)

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

Line charge revenues ($000) by price component *Not Required before DY2025*

	Total distribution line charge revenue	Total transmission line charge revenue	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)
Standardised price component			[Select one]			[Select one]			[Select one]			[Select one]		
EDB defined price component														
Not Required before DY2025														
DM1 - Principal Res - Low User	–	–			–			–			–			–
User	–	–			–			–			–			–
DM3 - Non-Principal Residence	–	–			–			–			–			–
Residence														
DM7 - Principal Res - Standard														
Standard														
less)														
or less)														
Metering)														
Metering)														
ND5 - Irrigation and Pumps														
ND6 - Unmetered 24 Hour														
Lighting														
ND12 - Builders Supply														
Based ToU														
Based	–	–			–			–			–			–
Capacity	–	–			–			–			–			–
Based	–	–			–			–			–			–
1 MW	–	–			–			–			–			–
IND - Individual Pricing	–	–			–			–			–			–
Discount (1 to 1,999 kWh)	–	–			–			–			–			–
Discount (2,000+ kWh)	–	–			–			–			–			–
Standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Check		Error												

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	–

Company Name	**Northpower**
For Year Ended	**31 March 2024**
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

9a: Asset Register

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)
9	All	Overhead Line	Concrete poles / steel structure	No.	53,759	53,896	137	2
10	All	Overhead Line	Wood poles	No.	1,137	1,111	(26)	2
11	All	Overhead Line	Other pole types	No.	48	–	(48)	2
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	296	295	(1)	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	28	28	(0)	3
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	13	14	1	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	8	8	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km		–	–	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	22	1	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	1	1	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.		–	–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	19	19	–	2
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	36	41	5	2
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	175	175	–	2
29	HV	Zone substation switchgear	33kV RMU	No.	4	4	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	38	39	1	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	59	58	(1)	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	158	158	–	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.	41	43	2	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3,507	3,507	(0)	2
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	272	275	3	3
39	HV	Distribution Cable	Distribution UG PILC	km	38	39	1	2
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.	33	35	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.	8,605	8,660	55	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	16	17	1	2
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	234	237	3	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	6,039	6,089	50	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	1,552	1,581	29	3
48	HV	Distribution Transformer	Voltage regulators	No.	12	12	–	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	116	117	1	4
50	LV	LV Line	LV OH Conductor	km	1,185	1,183	(2)	2
51	LV	LV Cable	LV UG Cable	km	837	864	26	2
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	418	422	4	2
53	LV	Connections	OH/UG consumer service connections	No.	63,445	64,073	628	2
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	381	396	15	2
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	23	23	–	4
57	All	Load Control	Centralised plant	Lot	6	6	–	4
58	All	Load Control	Relays	No	39,561	40,540	979	2
59	All	Civils	Cable Tunnels	km			–	N/A

Company Name	Northpower
For Year Ended	31 March 2024
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

9b: Asset Age Profile

8 Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

9	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
10	All	Overhead Line	Concrete poles / steel structure	No.	142	148	1,512	7,883	13,055	9,491	7,760	626	499	686	685	833	795	657	572	611
11	All	Overhead Line	Wood poles	No.	1	–	10	52	127	433	244	18	20	24	36	53	34	23	5	8
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	70	104	28	37	46	4	0	0	1	0	–	–	0	0
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	28	–	–	–	–	–	–	–	–	–	–	–
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	1	0	1	3	0	0	–	0	0	0	–
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	5	3	0	–	–	–	–	–	–	–	–	–	–
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	3	–	–	–	–	–	–	–	–	–	–
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	1	–	2	7	1	4	2	1	–	–	–	–	–	–	1	1
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	1	2	6	2	–	–	3	3	–	2	–	–	–	–	–	–
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	4	–	30
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	13	66	10	11	2	2	–	4	5	1	25	3	1	8
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	2	2	–	–	–	–	–	–	–
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	18	1	–	1	1	–	–	–	1	–	3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	5	22	6	–	–	–	5	1	3	1	–
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	5	13	20	1	–	5	–	4	–	–	9	31	–
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	1	10	7	4	–	–	1	2	1	–	2	–	–	–
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	9	18	83	538	697	656	571	72	35	47	31	65	31	21	21	19
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	1	0	8	30	7	7	12	9	15	24	27	20	8
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	5	9	15	6	2	1	–	0	0	1	0	–	0
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	–	–	1	1	–	–	1	8	–	1	2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	4	7	7	124	210	474	972	128	116	138	148	191	201	199	195	340
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	4	5	–	–	–	–	–	–	–	–	–	–
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	3	6	13	2	4	2	2	2	27	23	4	6
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	65	110	99	473	399	387	1,063	161	126	149	126	168	156	154	197	120
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	3	3	12	140	150	148	134	34	32	41	28	54	79	86	65	24
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	2	–	2	–	–	–	–	3	–	–	–	–
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	12	21	22	31	5	1	7	1	1	–	–	1	3
51	LV	LV Line	LV OH Conductor	km	1	1	20	147	167	492	170	10	8	10	21	22	19	14	6	5
52	LV	LV Cable	LV UG Cable	km	0	–	0	24	51	77	86	19	20	28	35	50	51	50	47	25
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	2	47	147	40	52	2	4	3	4	8	10	12	11	5
54	LV	Connections	OH/UG consumer service connections	No.	1	15	74	1,725	4,168	19,480	15,421	2,052	815	894	1,102	1,126	1,172	1,111	1,055	849
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	7	17	54	6	5	4	1	5	20	13	28	54
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	5	–	–	–	–	–	2	–	–	1
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	2	–	–	–	–	2	–	–	–	1	–
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	144	244	69	16	19	26
60	All	Civils	Cable Tunnels	km																

9	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year	No. with default dates	Data accuracy (1–4)
10	719	717	662	702	591	600	579	521	388	322	352	379	378	409	478	144		–	53,896	4,450	2
11	2	3	4	–	3	2	2	2	–	2	2	–	1	–	–	–		–	1,111	221	2
12	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–	2
13	0	0	–	1	0	–	–	–	–	–	1	2	–	0	0	–		–	295	2	3
14	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	28	–	3
15	3	0	–	0	–	2	0	–	–	–	0	0	1	1	1	0		–	14	0	3
16	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	8	–	4
17	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–	4
18	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	3	–	4
19	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–		–	0	–	4
20	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–	4
21	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–	4
22	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–	4
23	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	1	–	4
24	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	1		–	22	–	4
25	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	1	–	4
26	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–	4
27	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	19	2	2
28	1	–	–	–	–	–	–	–	–	–	–	–	–	6	–	–		–	41	23	2
29	5	–	1	2	2	–	–	–	5	1	4	1	–	–	3	–		–	175	5	2
30	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	4	–	4
31	2	–	–	–	1	1	–	–	–	–	5	3	2	–	–	–		–	39	–	4
32	2	–	–	2	–	–	5	1	4	–	–	–	1	–	–	–		–	58	–	4
33	17	12	–	–	1	–	–	–	–	–	17	11	12	–	–	–		–	158	–	4
34	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–	4
35	2	–	–	–	–	2	–	–	1	2	2	2	2	2	–	–		–	43	–	4
36	19	23	39	67	78	26	42	34	36	38	61	35	31	23	24	18		–	3,507	66	2
37	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–	4
38	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–	4
39	12	5	3	4	9	5	6	6	6	7	10	9	11	9	5	2		–	275	4	3
40	–	0	0	0	–	–	–	–	–	–	–	–	–	0	–	–		–	39	4	2
41	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	2	–	1
42	2	1	1	1	1	1	2	–	–	1	1	2	1	2	5	–		–	35	–	4
43	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	–	–	4
44	501	327	478	380	389	359	395	289	305	259	276	247	289	339	298	75		–	8,660	–	2
45	–	–	–	–	–	–	–	–	–	3	1	1	1	2	–	–		–	17	1	2
46	18	4	5	4	6	7	8	8	9	8	11	11	18	13	11	2		–	237	–	4
47	141	47	137	90	139	224	149	115	165	155	201	166	142	182	83	–		–	6,089	14	3
48	37	47	6	1	13	35	46	37	43	34	45	39	74	62	29	–		–	1,581	1	3
49	–	–	–	–	–	–	3	–	–	–	2	–	–	–	–	–		–	12	–	4
50	2	1	1	2	1	–	–	–	–	2	1	–	–	–	1	1		–	117	–	4
51	6	5	5	3	3	3	4	3	3	4	5	8	4	5	5	1		–	1,183	278	2
52	29	16	7	6	17	8	15	24	26	29	25	21	21	30	24	4		–	864	23	2
53	12	1	3	1	3	6	4	3	6	7	4	4	5	9	5	0		–	422	98	2
54	777	743	594	631	647	628	856	1,087	1,116	1,058	945	913	1,119	1,077	695	127		–	64,073	12,794	2
55	16	31	3	5	1	4	2	22	–	18	27	20	19	7	4	3		–	396	10	2
56	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–		–	1	–	4
57	5	5	–	3	–	–	–	1	–	–	–	–	–	1	–	–		–	23	–	4
58	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–		–	6	–	4
59	20	24	20	21	16	12	20	11	13	14	5	1,412	402	780	139	1		37,112	40,540	297	2
60																			–		N/A

Company Name	**Northpower**
For Year Ended	**31 March 2024**
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 **9c: Overhead Lines and Underground Cables**

sch ref		Overhead (km)	Underground (km)	Total circuit length (km)
10				
11	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
12	> 66kV	28	0	28
13	50kV & 66kV	75		75
14	33kV	220	26	246
15	SWER (all SWER voltages)			–
16	22kV (other than SWER)			–
17	6.6kV to 11kV (inclusive—other than SWER)	3,507	316	3,823
18	Low voltage (< 1kV)	1,183	864	2,046
19	**Total circuit length (for supply)**	5,013	1,205	6,218
20				
21	Dedicated street lighting circuit length (km)	174	248	422
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			122

sch ref				
23				
24	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
25	Urban	610	12%	
26	Rural	4,403	88%	
27	Remote only		–	
28	Rugged only		–	
29	Remote and rugged		–	
30	Unallocated overhead lines		–	
31	**Total overhead length**	5,013	100%	
32				
33		**Circuit length (km)**	**(% of total circuit length)**	
34	Length of circuit within 10km of coastline or geothermal areas (where known)	3,414	55%	
35				
36		**Circuit length (km)**	**(% of total overhead length)**	
37	Overhead circuit requiring vegetation management	5,013	100%	*Not required after DY2025*
38		**Total newly identified throughout the disclosure year**	**Total remaining at high risk at the disclosure year-end**	
39	Number of overhead circuit sites at high risk from vegetation damage		–	*Not required before DY2026*
40				

41 **Breakdown of overhead circuit sites at high risk from vegetation damage at disclosure year-end**

sch ref	Category of overhead circuit site	Number of overhead circuit sites at high risk from vegetation damage at disclosure year-end	Number of overhead circuit sites involving critical assets at disclosure year-end	
43	[Single tree]			*Not required before DY2026*
44	[Single tree - Urban]			*Not required before DY2026*
45	[Single tree - Rural]			*Not required before DY2026*
46	[Row of trees]			*Not required before DY2026*
47	[Span between two poles (X metres)]			*Not required before DY2026*
48	[Other]			*Not required before DY2026*
49	**Total number of sites**	–	–	*Not required before DY2026*

50 ** Insert new rows in table above Total line as necessary*

Company Name	Northpower
For Year Ended	31 March 2024

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 *	Average number of ICPs in disclosure year	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**
For Year Ended	**31 March 2024**
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 and Decommissionings**		
9	*Number of ICPs connected during year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Mass Market New ICPs	570	
12	Large Commercial and Industrial (ND9) New ICPs	1	
13	Very Large Industrial New ICPs	–	
14			
15			
16	** include additional rows if needed*		
17	**Connections total**	571	
18			
19	*Number of ICPs decommissioned during year by consumer type*		
20	*Consumer types defined by EDB**	**Number of decommissionings**	
21	Mass Market ICPs	134	
22	Large Commercial and Industrial (ND9) ICPs	2	
23	Very Large Industrial ICPs	–	
24			
25			
26	** include additional rows if needed*		
27	**Decommissionings total**	136	
28			
29	**Distributed generation**		
30	Number of connections made in year	517	**connections**
31	Capacity of distributed generation installed in year	3.16	**MVA**
32			
33	**9e(ii): System Demand**		
34			
35			
36	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
37	GXP demand	158	
38	*plus* Distributed generation output at HV and above	–	
39	**Maximum coincident system demand**	158	
40	*less* Net transfers to (from) other EDBs at HV and above	–	
41	**Demand on system for supply to consumers' connection points**	158	
42	**Electricity volumes carried**	**Energy (GWh)**	
43	Electricity supplied from GXPs	822	
44	*less* Electricity exports to GXPs	–	
45	*plus* Electricity supplied from distributed generation	15	
46	*less* Net electricity supplied to (from) other EDBs	–	
47	**Electricity entering system for supply to consumers' connection points**	837	
48	*less* Total energy delivered to ICPs	791	
49	**Electricity losses (loss ratio)**	46	5.5%
50			
51	**Load factor**	0.61	
52	**9e(iii): Transformer Capacity**		
53		**(MVA)**	
54	Distribution transformer capacity (EDB owned)	609	
55	Distribution transformer capacity (Non-EDB owned)	9	
56	**Total distribution transformer capacity**	618	
57			
58		**(MVA)**	
59	Zone substation transformer capacity (EDB owned)	365	
60	Zone substation transformer capacity (Non-EDB owned)	14	
61	**Total zone substation transformer capacity**	379	

Company Name	**Northpower**
For Year Ended	**31 March 2024**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

10(i): Interruptions

Interruptions by class	**Number of interruptions**
Class A (planned interruptions by Transpower)	–
Class B (planned interruptions on the network)	486
Class C (unplanned interruptions on the network)	510
Class D (unplanned interruptions by Transpower)	–
Class E (unplanned interruptions of EDB owned generation)	–
Class F (unplanned interruptions of generation owned by others)	–
Class G (unplanned interruptions caused by another disclosing entity)	–
Class H (planned interruptions caused by another disclosing entity)	–
Class I (interruptions caused by parties not included above)	–
Total	996

Interruption restoration	**≤3Hrs**	**>3hrs**
Class C interruptions restored within	362	148

SAIFI and SAIDI by class	**SAIFI**	**SAIDI**
Class A (planned interruptions by Transpower)	–	–
Class B (planned interruptions on the network)	0.68	204.7
Class C (unplanned interruptions on the network)	4.31	213.4
Class D (unplanned interruptions by Transpower)	–	–
Class E (unplanned interruptions of EDB owned generation)	–	–
Class F (unplanned interruptions of generation owned by others)	–	
Class G (unplanned interruptions caused by another disclosing entity)	–	–
Class H (planned interruptions caused by another disclosing entity)	–	–
Class I (interruptions caused by parties not included above)	–	–
Total	4.99	418.1

Normalised SAIFI and SAIDI	**Normalised SAIFI**	**Normalised SAIDI**	
Classes B & C (interruptions on the network)	4.99	394.9	*Not required after DY2024*

Transitional SAIFI and SAIDI (previous method)	**SAIFI**	**SAIDI**
Class B (planned interruptions on the network)	0.68	204.7
Class C (unplanned interruptions on the network)	3.75	206.2

Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'. ***This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***

Company Name	**Northpower**
For Year Ended	**31 March 2024**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

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

Cause	SAIFI	SAIDI	
Lightning	0.16	4.2	
Vegetation	0.34	19.3	
Adverse weather	0.78	49.3	
Adverse environment	0.00	0.1	
Third party interference	0.26	20.1	
Wildlife	0.32	11.3	
Human error	0.02	0.9	
Defective equipment	0.83	61.5	
Cause unknown	1.61	46.8	*Not required after DY2024*
Other cause			*Not required before DY2025*
Unknown			*Not required before DY2025*

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	0.00	0.0
Overhead contact	0.10	6.0
Vandalism	0.00	0.0
Vehicle damage	0.14	13.4
Other	0.02	0.6

Breakdown of vegetation interruptions (vegetation cause)	SAIFI	SAIDI	
In-zone			*Not required before DY2026*
Out-of-zone			*Not required before DY2026*

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	0.04	13.9
Subtransmission other	–	–
Distribution lines (excluding LV)	0.56	167.7
Distribution cables (excluding LV)	0.09	23.2
Distribution other (excluding LV)	–	–

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.67	42.6
Subtransmission cables	0.06	2.7
Subtransmission other	–	–
Distribution lines (excluding LV)	3.43	157.4
Distribution cables (excluding LV)	0.15	10.6
Distribution other (excluding LV)	–	–

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	16	323	4.95
Subtransmission cables	2	26	7.69
Subtransmission other	–		
Distribution lines (excluding LV)	470	3,507	13.40
Distribution cables (excluding LV)	22	316	6.96
Distribution other (excluding LV)	–		
Total	510		

Company Name	**Northpower**
For Year Ended	**31 March 2024**
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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

10(vi): Worst-performing feeders (unplanned)

Not required before DY2025

SAIDI

Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

SAIFI

Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

Customer Impact

Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1							
2							
3							
4							

[1] *Extend table as necessary to disclose all worst-performing feeders*

Company Name	Northpower
For Year Ended	31 March 2024

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 11 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 ROI and vanilla ROI for disclosure year were 4.62% and 5.32% respectively. This compares to 5.91% and 6.43% for the previous year.

The reduction in the ROI is largely a result of the lower CPI for FY24.

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; and

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

Box 2: Explanatory comment on regulatory profit

Other regulatory income of $2,924k relates to value added work on charged to customers as well as a settlement from a supplier and an early contract termination fee. This income was all received in the normal course of business.

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 was no incurred merger and acquisition expenditure 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 roll-forward in Schedule 4 is determined in accordance with the IM requirements and is consistent with prior year. • There were no reclassifications made. • Disposed assets of $985k mainly relates items that have been moved into and out of strategic spares. •Shared assets in the RAB have been allocated with the application of the ABAA approach for this disclosure year. Refer box 8 for details.

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

$19k expenditure or loss in regulatory profit before tax but not tax deductible relates to non deductible entertainment expenditure.

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)

The tax effect of other temporary differences of $167k represents tax on the movement between FY23 and FY24 in the following provisions:

- Holiday leave provisions;
- Long service leave provisions;
- Bonus accrual;
- Doubtful debt provision;
- Cost of financing

Cost allocation (Schedule 5d)

10. 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 7: Cost allocation

Cost allocations were calculated using the ABBA methodology as per Part 2.1 of the IM determination for business support.

- People and capability costs allocated using headcount as causal allocator consistent with prior year.
- Digital costs allocated using either headcount, licence numbers or time as causal allocators.
- Finance costs allocated using gross margin as a proxy allocator consistent with prior year.
- Facilities costs allocated using floor space as a causal allocator consistent with prior year.
- Corporate costs allocated using non-current assets as a proxy allocator consistent with prior year.

Asset allocation (Schedule 5e)

11. 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 8: Commentary on asset allocation

Asset allocations were calculated using the ABAA methodology as per Part 2.1 of the IM determination.

A summary of RAB assets that were allocated are as follows:

• Sub transmission line, distribution and LV line assets – Shared pole assets used for fibre and network assets (proxy allocator).

• Distribution and LV cables – 100% of CBD ducts and civils exclusively used for the Fibre business.

• Other network assets – Backhaul fibre assets shared between the Fibre and Network business (causal allocator).

• Land and buildings – Estimated area shared between regulated network and non- network businesses (proxy allocator).

The method of asset allocations is consistent with the prior year. No items were reclassified.

Capital Expenditure for the Disclosure Year (Schedule 6a)

12. In the box below, comment on expenditure on assets for the disclosure year, as disclosed in Schedule 6a. This comment must include-

    12.1 a description of the materiality threshold applied to identify material projects and programmes described in Schedule 6a;

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

Box 9: Explanation of capital expenditure for the disclosure year

The largest component of the capital expenditure was asset replacement and renewal, followed by system growth. The asset replacement and renewal trend is consistent with FY21, FY22 and FY23. The higher system growth number reflects the completion of the new Mangawhai Central substation.

Capex projects or programmes above a $50k threshold have been described in schedule 6a, and where possible, we have aggregated projects below this threshold. No items were reclassified.

Operational Expenditure for the Disclosure Year (Schedule 6b)

13. In the box below, comment on operational expenditure for the disclosure year, as disclosed in Schedule 6b. This comment must include-

    13.1 Commentary on assets replaced or renewed with asset replacement and renewal operational expenditure, as reported in 6b(i) of Schedule 6b;

    13.2 Information on reclassified items in accordance with subclause 2.7.1(2);

    13.3 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 10: Explanation of operational expenditure for the disclosure year

Asset replacement and renewal operating expenditure relates to work done to make good on defects identified during scheduled preventative maintenance inspections.

- There are no reclassified items to report.
- There is no material atypical expenditure included in the operational expenditure.
- Operational expenditure has increased across vegetation, routine and corrective and system operations and support but service interruptions and emergencies and asset replacement and renewal have reduced following the large impact of cyclone Gabrielle in FY23.
- A reassessment of the allocations has resulted in an increase in system operations and network support.
- Business support – please refer Box 7

Variance between forecast and actual expenditure (Schedule 7)

14. 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 11: Explanatory comment on variance in actual to forecast expenditure
Asset expenditure was overall 6% lower than the target expenditure. The main underspends were in system growth and quality of supply.

• Network Opex was 16% higher than target with service interruptions and emergencies, vegetation management and asset replacement and renewal all higher than the target. It was a more stable year in terms of the weather but there were still a number of storms that impacted.

• Non-network Opex was only 5% lower than target.

Information relating to revenues and quantities for the disclosure year

15. In the box below provide-

15.1 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

15.2 explanatory comment on reasons for any material differences between target revenue and total billed line charge revenue.

Box 12: Explanatory comment relating to revenue for the disclosure year
Target revenue disclosed before the start of the year was 4% higher than the total billed line charge revenue.

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 13: Commentary on network reliability for the disclosure year
Defective equipment had the highest effect on network performance, possibly due to the after effects of Cyclone Gabrielle which occurred in February 2024. There were some multi-day storms which further affected network performance contributed by adverse weather.

Planned SAIDI stands high with the continuing focus on asset renewal across the network to ensure resilience and reliability.

Insurance cover

17. In the box below, provide details of any insurance cover for the assets used to provide electricity distribution services, including-

17.1 The EDB's approaches and practices in regard to the insurance of assets used to provide electricity distribution services, including the level of insurance;

17.2 In respect of any self insurance, the level of reserves, details of how reserves are managed and invested, and details of any reinsurance.

Box 14: Explanation of insurance cover
Significant assets located in one place (e.g. zone substations, control room, other buildings) 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

18. 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:

18.1 a description of each error; and

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

Box 15: Disclosure of amendment to previously disclosed information
No amendments to previously disclosed information.

Company Name	Northpower
For Year Ended	31 March 2024

Schedule 15 Voluntary Explanatory Notes

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018.)

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

S8. Billed Quantities + Revenues – ND7 consumption

Excludes consumption by private streetlights as we do not hold this information because we invoice on a wattage basis rather than consumption. Consumers provide voluntary consumption data for public streetlights only. This is consistent with prior years and does not have a significant impact on the disclosures in schedule 8.

S9b. Asset Age Profile

The asset age profile data has been presented by calendar year, which is consistent with prior years. This treatment has been adopted because we do not hold information on the month of installation for historic assets and therefore are not able to align the data to 31 March year ends.

S9c. Urban and Rural circuit length

The breakdown of the Urban and Rural circuit length has been calculated using the urban-rural 2023 generalised layer from Stats NZ. This reflects a notable change in the expansion of urban areas in several areas and Mangawhai has transitioned from a rural settlement to a small urban area.

S10 Report on Network Reliability

Reliability measures have been updated from 1 April 2024 in line with the Commerce Commission requirements outlined in Tranche 1 of the Targeted Information Disclosure Review (TIDR) project.

Previously during the interruption to supply, if some customers were temporarily restored for a short period due to switching operations carried out in the course of locating a fault (e.g. opening a switch, reclosing a circuit breaker to identify which section has the fault, and repeating this along the circuit until the fault is identified) Northpower treated this activity as one interruption because, until the fault was located and addressed, supply had not properly been restored along the HV.

From 1 April 2024 successive interruptions have been recorded as an additional SAIFI and SAIDI value if restoration of supply occurs for longer than one minute before being interrupted again. Comparative results using the EDB's current method will be produced for DY24 and DY25.

NORTHPOWER NETWORK YEAR TO 31 MARCH 2024 ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE (EDID) FOR RELATED PARTY TRANSACTIONS

Table of Contents

Northpower

Summary of Northpower Network's Related Party Transactions

(Clause 2.3.8 of EDID requirements)

Related Party	Nature of Relationship	Principal Activity of Related Party	FY24 Expenditure with Related Party
Northpower Contracting Division	Both Northpower Network and Contracting division are part of Northpower Limited	The Contracting division provides maintenance and construction services for the electricity network.	Capital expenditure $27.9m Operating expenditure (maintenance) $15.3m
Northpower Fibre Limited	Northpower Limited is a shareholder of Northpower Fibre Limited	Northpower Fibre Limited owns and operates an ultra-fast broadband network in the Whangarei area.	Operating expenditure (leased fibre scada circuit for communications) $86k
Busck Prestressed Concrete Limited	Mr Paul Yovich is a Trustee of Northpower Electric Power Trust, the Shareholder of Northpower Limited. Mr Yovich is also a Trustee of a Shareholder of Busck Prestressed Concrete Limited.	Supplier of concrete products to the network, mainly poles (Note: the majority of purchases from this supplier are made by Northpower Contracting division. This related party disclosure is for purchases made directly by Northpower Network.)	Capital expenditure $0 Operating expenditure $0k
Electricity Engineers' Association (EEA)	Ms Josie Boyd is the COO Network and an Executive Committee Member of the Electricity Engineers' Association.	Professional engineers employed by Northpower Network are members of the EEA and purchase products from EEA.	Operating expenditure $43k

Northpower

Summary of Northpower Network's Policy in Respect of Procurement of Assets or Goods or Services from any Related Party

(Clause 2.3.10 of EDID requirements)

Purpose

This is a summary of the policy that outlines Northpower Network's approach to purchasing goods, services or assets from its related parties, including how those assets are valued.

Introduction

This document outlines Northpower Network's approach to purchasing goods, services or assets from its related parties, including how those assets are valued.

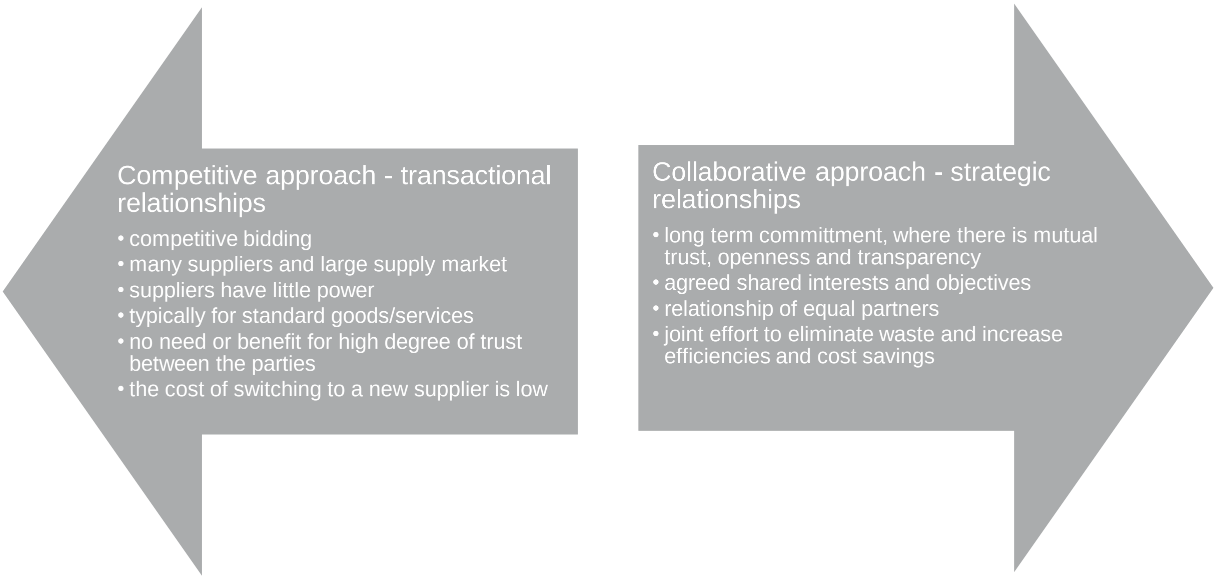
Procurement Objectives

The following objectives will inform Network's decision around the procurement of goods and services:

1. Ensuring that the services delivered meet the requirements and expectations of the consumers of Whangarei and Kaipara.
2. A delivery model that is cost effective and delivers efficiencies for the long-term benefit of consumers.
3. Achieving a high performing HSQE culture across all areas of its business, including staff and contractors.
4. The delivery of works programmes in accordance with Northpower's asset management strategies, including accessing resources to meet peak workloads.
5. Achieving innovation and continuous improvement in the areas identified above.

The choice around suppliers and procurement models, including transactions with related parties, will depend on the existing market for the specific goods or services, the strategic importance of the services, and the long-term needs of Network and its consumers.

Strategic supplier relationships are more likely to be based on a collaborative approach, underpinned by long term relationships. In contrast, goods or services with characteristics supporting a transactional relationship are likely to be subject to market contestability.



Where goods or services are not acquired through market contestability, Northpower will ensure that transactions are valued as if they were an arm’s-length transaction.

Valuation of Transactions

Transactions between Network and its related parties will be conducted and valued as if it were an arm’s-length transaction.

To meet these requirements, the following principles will be applied to all transactions with a related party who is providing goods or services to Network:

1. The value of a good or service acquired by Network must be given a value not greater than if that transaction had the terms of an arm’s-length transaction;
2. The value of an asset or good or service sold or supplied to Network must be given a value not less than if that transaction had the terms of an arm’s-length transaction;
3. Network will use an objective and independent measure in determining the terms of an arm’s-length transaction for the purpose of principles 1 and 2 above.

For the purpose of principle 1, where a good or service is acquired from a third party and then on-sold to a related entity, the value of the subsequent transfer between related entities must reflect the amount charged by the third party.

Objective & Independent Measures of Value

Northpower will ensure that transactions with its related parties are valued on arm’s-length terms by utilising independent and objective measures to establish that a related party transaction value is consistent with the value that would have otherwise been charged by an unrelated party commissioned to do the same work.

Methods used may include any or all of the following depending on the nature of the proposed transaction, the information reasonably available and what is practicable in the circumstances given the market for the relevant services.

- Commissioning a third party to undertake market benchmarking of the prices of substantially similar good or services.

- Conducting a tendering process for the goods or services.
- Undertaking internal benchmarking of the related party transactions against substantially same goods or services provided (by the related party) to its other customers.
- Engaging an expert to undertake an independent valuation to determine market value of the goods or service.

Procurement processes

External procurement processes will follow the Northpower Group Procurement Policy. Subject to Appendix 2 – Delegated Authority for Related Parties, all transactions, including those with related parties, must follow the Northpower Group Delegated Authorities Policy.

Confidentiality

The Northpower Group will adopt appropriate processes to protect the confidential and commercially sensitive information of its customers, its related parties and suppliers. These provisions include:

- The company will comply with the protocols outlined in Appendix 1 – Tendering involving Related Parties, where a tendering process is used.
- Appropriate protocols include information barriers, confidentiality undertakings and anonymisation of data.

Contractual Arrangements

Contractual arrangements with related parties will replicate good industry practice, be subject to regular review against market benchmarks, and may include an independent review.

Independent Representation

In some circumstances, it may be necessary for Network and its related parties to engage separate legal representation to provide sign off on the respective commercial terms.

Success Measures (Outcomes)

Successful implementation of this Network Policy will achieve the following outcomes:

- The Network Policy principles and objectives are met.
- Related party transactions are of a comparable value to relevant third party transactions.
- Network procurement processes are followed.

Tendering Involving Related Parties

The protocols set out below will be implemented by Northpower Network in order to receive and evaluate bids from related parties alongside third party contractors on a fair and compliant basis. These will also enable Northpower to mitigate process risks and enhance the attractiveness of the project for tenderers considering whether or not to submit a response.

- Disclosure that a related party has the capability to perform the project and will be invited to submit a bid.
- Disclosure of Evaluation Criteria in tender documents.
- Information barriers between Network and its related parties.
- Confidentiality undertakings required from Tenderers.
- Undertaking that pre-existing Intellectual Property is retained by Tenderers.
- Documentation of the Procurement Process to demonstrate probity.
- Briefings and de-briefings with successful and unsuccessful Tenderers.

The following two protocols may also be considered for sensitive RFPs

- Paying a stipend to Tenderers
- Appointing a Probity Adviser

A description of how Northpower Network's related party policy is applied in practice

(Clause 2.3.12.1 of EDID requirements)

Large capital projects (typically a defined set of works with a value of over $1 million) conducted by Northpower Network are generally based on fixed price contracts. EDB management will determine whether these projects should be subject to a competitive tender process or negotiated directly with Northpower Network's contracting partner, Northpower Contracting Division. In assessing whether these projects should be subject to tender, the EDB considers:

- The urgency of the project in terms of network function and safety
- Contractor availability and capability
- Whether the project will be seen as attractive to external contractors. This review involves factors such as the size of the project, the number of crews required, the type of work being undertaken, travel and mobilisation costs.

Competitive tender processes follow established tender processes that are based on industry recognised tendering and contracting frameworks (generally Standard NZS3910). Northpower Contracting Division is given the option to participate in the competitive tender process.

The specialised nature of construction and maintenance services for the EDB, including management of safety risks, dynamic workflow requirements and short response times along with the value of the work offered and efficiency benefits, lends itself to Northpower EDB establishing a preferred supplier relationship for the procurement of these services. Northpower EDB has this relationship with Northpower Contracting, which means that they complete the majority of the EDB's capital (other than tendered) and maintenance work. The Northpower Contracting Division is an established provider of construction and maintenance services for electrical networks for a number of EDB's. This provides the capability and scale to ensure the division is well placed to provide high quality and efficient services.

Work negotiated directly with the Northpower Contracting Division's Northland region is based on negotiated labour, plant and unit rates. With the exception of tendered projects, all work completed by Northpower Contracting's Northland region is governed by a field services agreement (referred to as the Service Level Agreement (SLA)). The SLA outlines how Northpower Network and Contracting's Northland region will work together, specifies the scope of services provided by the Contracting's Northland region, details rates, and includes a set of KPI's. The agreement is negotiated between representatives of the two Northpower divisions and approved by the respective Executives. Work completed by Northpower Contracting's other regions is priced at the project rates offered to their local Network customers.

A description of any Northpower Network policies or procedures that require or have the effect of requiring the consumer to purchase assets or goods or services from a related party

(Clause 2.3.12.2 of EDID requirements)

To work on or near Northpower's electricity distribution network, a contractor must be deemed competent and authorised to complete the work undertaken to satisfactorily meet Network standards.

Network extensions or customer initiated works must be undertaken by a Network approved contractor.

No external contractor is authorised for the following customer chargeable work:

a) HV network enhancements.

b) Third party network damage.

Due to risk to people and property and with any delay, no external contractor is authorised to remediate third party network damage. For completeness, the cost of remedying third party network damage, which is generally recovered from the responsible party, remains part of the services provided under the SLA.

Representative examples of how Northpower Network's Related Party Policy has been applied for the procurement of assets or goods or services and how arm's length terms were tested

(Clauses 2.3.12.3 – 2.3.12.5 of EDID requirements)

Capex Projects: Competitive Tender

There were no competitive tenders that involved Northpower Contracting Division and external parties in the 2024 financial year.

Directly negotiated work with Northpower Contracting Division

Work completed by Northpower Contracting Division under direct negotiation is governed by a SLA and negotiated rates. Both the rates and SLA are negotiated between the divisional management teams and final approval is required from the Executive Managers of the respective divisions.

Northpower's Corporate Finance Division has completed industry benchmarking of the related party transactions between Northpower Network and Northpower Contracting Division for the year ended 31 March 2024. The Finance Division operates independently from Northpower Network and Contracting divisions and provides an impartial view. This arm's-length assessment focused on:

- Assessing how the Northpower Contracting Division sets rates charged to Northpower Network, compared to other customers;
- Comparing rates between a selection of customers;
- Comparing margins earned by the Northpower Contracting Division for a selection of customers;
- Comparing year-on year movements in rates by customer, labour type and unit cost type;
- Reviewing the management of the supplier relationship;
- Confirming the approval process of the SLA and agreed rates.

This assessment concluded that the related party transactions between Northpower Network and Northpower Contracting Division meet the valuation requirements outlined in disclosure determination paragraph 2.3.6.

Opex Programme: Vegetation

Vegetation control for Northpower's EDB has been completed by Northpower Contracting Division and a third party. An RFP was undertaken in June 2022 and rates from Northern Contracting and two other external parties from the RFP were compared by Northpower's Corporate Finance Division. This comparison concluded that the vegetation control rates between Northpower Network and Northpower Contracting Division meet the valuation requirements outlined in disclosure determination paragraph 2.3.6.

Procurement Examples

The following provide examples of the procurement process for work completed by Northpower Contracting under the SLA.

Faults Services

On 3rd December 2023 at 14.54hours, the dispatcher received a call from New Zealand Police reporting an incident where a vehicle had hit a pole on Brown Road Kaiwaka (Pole no 11960) and requested Northpower's attendance. The Dispatcher recorded this job in the faults management system under reference number 377470 and dispatched a contracting fault crew to the site. Traffic management was also required while the pole was replaced.

Northpower Contracting recorded the labour, plant, equipment and materials used in replacing the pole as detailed on the service request. An invoice was issued to Network (Faults invoicing batch 2060664) along with a copy of the unit rate billing sheet. This was approved for payment by Network.

Planned Maintenance

Northpower Network's maintenance is split between distribution and sub-stations. Each has an annual schedule of maintenance required. The maintenance tasks are created in our maintenance system and are packaged into a work pack and issued to Northpower Contracting. The current process is that a purchase order (PO) is automatically created in the ERP system (JDE) when the work pack is issued. Work is completed by Northpower Contracting and any defects that require further follow up are recorded. Northpower Contracting raise an invoice, which is matched to the PO in the ERP system. The invoice is automatically approved if it matches the purchase order; otherwise, the invoices are manually reviewed and approved if the charges are appropriate. Invoices that require approval are highlighted in an exceptions report.

Defects identified when Northpower Contracting are completing the preventative maintenance tasks are recorded on a data sheet and Northpower Contracting create 'tasks' in Wasp (the asset maintenance system). These are then planned and packaged into work packs by Northpower Contracting and sent to the Network team for approval before being sent back to Northpower Contracting to carry out the work.

Vegetation

A prioritised annual vegetation maintenance programme is established using a risk-based approach. Specialist inspectors carry out risk-based assessments on sites where vegetation poses a risk to the Network. They prepare a plan to mitigate the risk including an estimate of resource required. Details of any cutting work required is recorded in the maintenance system in a work pack. There is a built-in mechanism to approve and track works variations when there is a change in scope between the assessment and cutting stages. The work is then assigned to vegetation contractors (Northern Contracting or an external contractor) for clearance based on risk and available resource. If Northpower Contracting are carrying out the work, they invoice the Network once the work is complete. If the invoice is in line with the purchase orders, they are automatically approved. If there are variances Network management review and once the variance is understood and accepted the invoices are approved.

Capital Project

The conductor replacement programme is an example of a corrective capex project. There are routine sample tests carried out to identify conductors that are end of life. Conductors to include in conductor replacement projects are identified by the condition of the conductors and age. Network issue contracting a Project Job Sheet detailing works required. Northpower Contracting prepare a Project Work Proposal detailing the methodology, timeline, and pricing to carry out the works. The Project Work Proposal is reviewed by Network, ensuring the proposal satisfies the requirements of the Project Job Sheet. If accepted, Network issues a purchase order accepting Northpower Contracting Project Work Proposal. Invoicing is done on a monthly basis as works are completed. Network approves the invoice if it is in line with the purchase order.

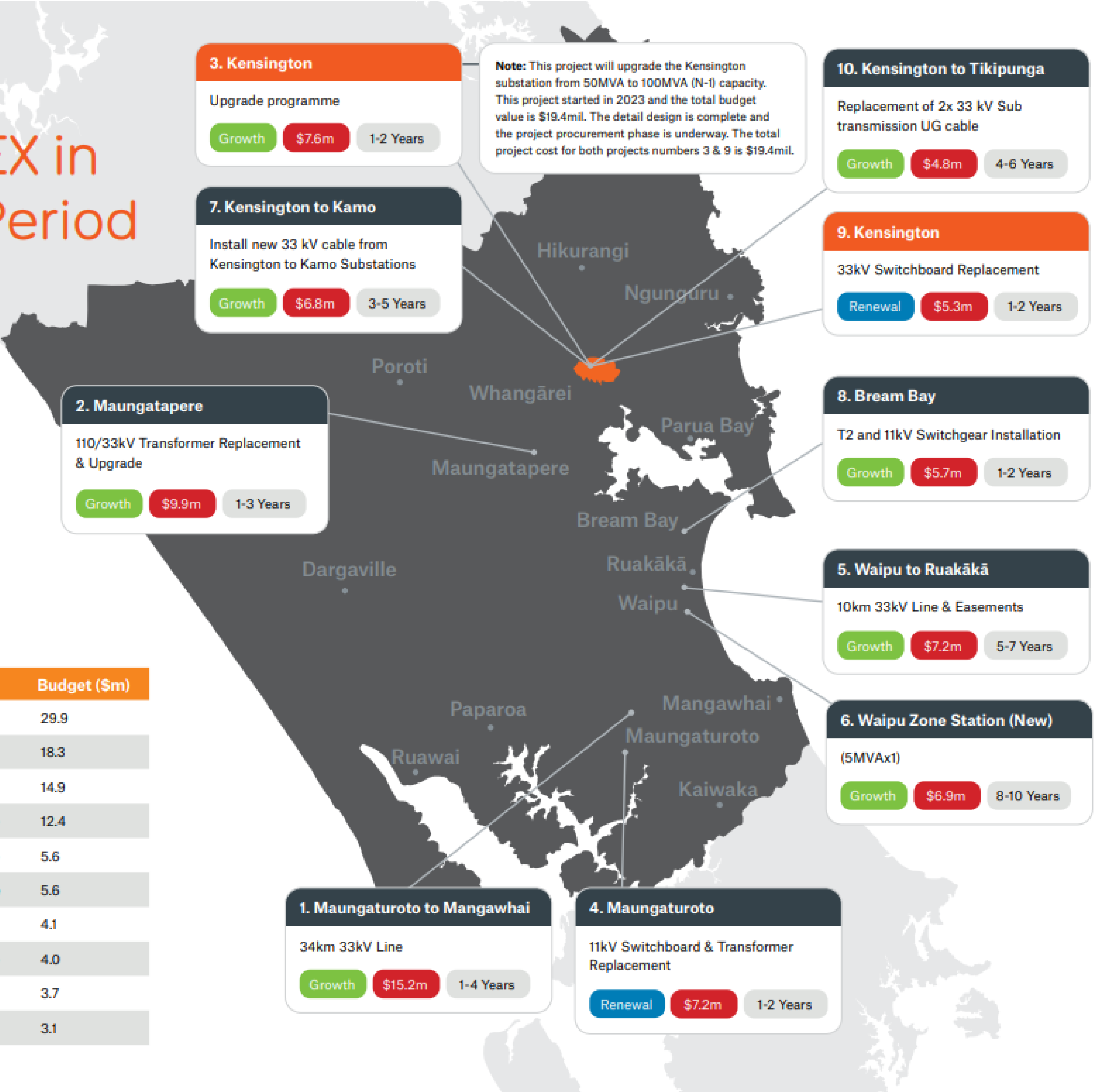
Northpower

CAPEX and OPEX in AMP Planning Period

Capital Project
Currently not indicated for supply by a related party.

Capital Project
To be supplied by a related party.

Operating Program
With the exception of a small amount of vegetation management, this program is forcast to require the Capital Project supply of assets or goods or services by a related party.



Opex Programme	Maintenance type	Budget ($m)
Vegetation	Corrective maintenance	29.9
Overhead lines	Remedial maintenance	18.3
Overhead lines	Corrective maintenance	14.9
Overhead lines	Preventative maintenance	12.4
Distribution earthing	Preventative maintenance	5.6
Customer equipment	Value added maintenance	5.6
Ground mounted substations	Corrective maintenance	4.1
Ground mounted substations	Preventative maintenance	4.0
Underground cables	Remedial maintenance	3.7
Cable location	Remedial maintenance	3.1

Northpower

Standalone document - Narrative Describing Practices that Complies with Clause 17.2.2 of Attachment A

(Clause 17.2.2)

Purpose

This is a summary of the practices Northpower is taking towards improving low voltage visibility to better understand and forecast low voltage constraints.

Low Voltage Network Visibility and Modelling

We are focusing on improving the data on our Low Voltage (LV) networks and using this to more accurately model the networks to identify constraints.

During FY22 we carried out an initial modelling exercise of all our LV networks individually. This was done using a mixture of real data stored in information systems and assumptions for missing data. This modelling exercise has given us a good understanding of what data we require and what areas we should be targeting for data capture.

We have installed LV monitors on a selection of distribution substations. The initial roll-out has targeted specific distribution substations which were expected to have the most benefit. These are in areas where we are seeing increased PV and EV activity, sites that will allow us to gain a better understanding of customer load behaviours, and areas that are most likely to have existing constraints.

Following our initial modelling exercise we have identified some asset data that needs to be improved. We are working on addressing gaps to improve the accuracy of our modelling.

We are working with metering providers (MEPs) to gain access to smart meter data from homes on our network, this will provide historical voltage & power data for around 40k ICPs (~63%) and gain visibility into 98% of our LV networks. We are also working with companies who can provide LV insights using this data and allow us to identify and forecast constraints on the LV network.

We are working on importing our full GIS to our SINCAL interface for modelling and forecasting. This will increase the accuracy of modelling the LV network, DER uptake, and forecasting throughout our network.

Northpower

DIRECTORS' CERTIFICATE

We, Mark Trigg and Kerry Friend, 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, and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and

b) The historical information used in the preparation of Schedules 8, 9a, 9b, 9c, 9d, 9e, 10, and 14 has been properly extracted from the Northpower Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained.

c) In respect of information concerning assets, costs and revenues valued or disclosed in accordance with clause 2.3.6 of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012, we are satisfied that-

    i. the costs and values of assets or goods or services acquired from a related party comply, in all material respects, with clauses 2.3.6(1) and 2.3.6(3) of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5)(a)-2.2.11(5)(b) of the Electricity Distribution Services Input Methodologies Determination 2012; and
    ii. the value of assets or goods or services sold or supplied to a related party comply, in all material respects, with clause 2.3.6(2) of the Electricity Distribution Information Disclosure Determination 2012.

Director	Director
Mark Trigg	Kerry Friend
Date 28 August 2024	Date 28 August 2024

Deloitte.

INDEPENDENT ASSURANCE REPORT
TO THE DIRECTORS OF NORTHPOWER LIMITED AND TO THE COMMERCE COMMISSION
ON THE DISCLOSURE INFORMATION
FOR THE DISCLOSURE YEAR ENDED 31 MARCH 2024
AS REQUIRED BY
THE ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE DETERMINATION 2012
(CONSOLIDATED 6 JULY 2023)

Northpower Limited (the company) is required to disclose certain information under the Electricity Distribution Information Disclosure Determination 2012 (consolidated 6 July 2023) (the Determination) and to procure an assurance report by an independent auditor in terms of section 2.8.1 of the Determination.

The Auditor-General is the auditor of the company.

The Auditor-General has appointed me, Silvio Bruinsma, using the staff and resources of Deloitte Limited, to undertake a reasonable assurance engagement, on his behalf, on whether the information prepared by the company for the disclosure year ended 31 March 2024 (the Disclosure Information) complies, in all material respects, with the Determination.

The Disclosure Information that falls within the scope of the assurance engagement are:

- Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10 and 14 (limited to the explanatory notes in boxes 1 to 11) of the Determination.

- Clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 20 May 2020) (the IM Determination), in respect of the basis for valuation of related party transactions (the Related Party Transaction Information).

Opinion

In our opinion, in all material respects:

- as far as appears from an examination, 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, sourced from the company's financial and non-financial systems;

- the Disclosure Information complies, in all material respects, with the Determination; and

- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

Basis for opinion

We conducted our engagement in accordance with the Standard on Assurance Engagements (SAE) 3100 (Revised) *Compliance Engagements* ("SAE 3100 (Revised)"), issued by the New Zealand Auditing and Assurance Standards Board. An engagement conducted in accordance with SAE 3100 (Revised) requires that we comply with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information*.

We have obtained sufficient recorded evidence and explanations that we required to provide a basis for our opinion.

Key Assurance Matters

Key assurance matters are those matters that, in our professional judgement, required significant attention when carrying out the assurance engagement during the current disclosure year. These matters were addressed in the context of our compliance engagement, and in forming our opinion. We do not provide a separate opinion on these matters.

Deloitte.

Key Assurance Matter	How our procedures addressed the key assurance matter
Accuracy and completeness of the quantity and duration of electricity outages and ICP numbers The Information Disclosure Determination defines certain quality measures in relation to the number and duration of interruptions, faults, and causes of faults. These quality measures are expressed in the form of SAIDI and SAIFI values. The accuracy of the data is a key audit matter because information on the frequency and duration of outages is an important measure about the reliability of electricity supply. The completeness of the data is a key audit matter because the details of the faults are entered manually into the fault outage report, which is used to calculate the SAIDI/ SAIFI. The feeder maps capture the Individual Connection Point data that is used in the calculation of the SAIDI and SAIFI values. These Feeder Maps are updated only once every 2 years.	We have: • Obtained an understanding of the company's methods by which electricity outages and their duration are recorded; • Assessed the design and implementation of key controls related to the recording, reconciliation and review of the outage data obtained from the outage report; • For a sample of outages, observed the number of consumers affected from the feeder maps on the date of testing and assessed the reasonability of this number against impacted consumers recorded in the data; • Reviewed the recorded detail for a sample of outages and ensured that the appropriate dates and times were used and the outage was started and ended by an appropriate individual; and • Recalculated the normalised SAIDI and SAIFI using the predetermined boundary limits.

Directors' responsibilities

The directors of the company are responsible in accordance with the Determination for:

- the preparation of the Disclosure Information; and
- the Related Party Transaction Information.

The directors of the company are also responsible for the identification of risks that may threaten compliance with the schedules and clauses identified above and controls which will mitigate those risks and monitor ongoing compliance.

Auditor's responsibilities

Our responsibilities in terms of clauses 2.8.1(1)(b)(vi) and (vii), 2.8.1(1)(c) and 2.8.1(1)(d) are to express an opinion on whether:

- as far as appears from an examination, the information used in the preparation of the audited Disclosure Information has been properly extracted from the company's accounting and other records, sourced from its financial and non-financial systems;

- as far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information required by the Determination have been kept by the company and, if not, the records not so kept;

- the company complied, in all material respects, with the Determination in preparing the audited Disclosure Information; and

- the company's basis for valuation of related party transactions in the disclosure year has complied, in all material respects, with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the IM Determination.

To meet these responsibilities, we planned and performed procedures in accordance with SAE 3100 (Revised), to obtain reasonable assurance about whether the company has complied, in all material respects, with the Disclosure Information (which includes the Related Party Transaction Information) required to be audited by the Determination.

An assurance engagement to report on the company's compliance with the Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements. The procedures selected depend on our judgement, including the identification and assessment of the risks of material non-compliance with the requirements.

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error or non-compliance with the Determination may occur and not be detected.

A reasonable assurance engagement throughout the disclosure year does not provide assurance on whether compliance with the Determination will continue in the future.

Restricted use

This report has been prepared solely for your exclusive use in accordance with clause 2.8.1(1)(a) of the Determination and is provided solely for the purpose of establishing whether the compliance requirements have been met. We disclaim any assumption of responsibility for any reliance on this report to any person, other than you, or for any other purpose than that for which it was prepared.

Independence and quality control

We complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the requirements of Professional and Ethical Standard 1 *International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand)* (PES 1) issued by the New Zealand Auditing and Assurance Standards Board; and

- quality management requirements, which incorporate Professional and Ethical Standard 3 *Quality Management for Firms that perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements* (PES 3) issued by the New Zealand Auditing and Assurance Standards Board. PES 3 requires our firm to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

The Auditor-General, and his employees, and Deloitte Limited and its partners and 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 trading activities of the company, this engagement, other regulatory engagements, and the annual audit of the company's financial statements, we have no relationship with or interests in the company or its subsidiaries.

Silvio Bruinsma

Silvio Bruinsma
Deloitte Limited
On behalf of the Auditor-General
Auckland, New Zealand
28 August 2024

Deloitte.

REPORT OF THE INDEPENDENT APPRAISER
TO THE DIRECTORS OF NORTHPOWER LIMITED AND TO THE COMMERCE COMMISSION
ON THE RELATED PARTY TRANSACTIONS
FOR THE DISCLOSURE YEAR ENDED 31 MARCH 2024
AS REQUIRED BY
THE ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE DETERMINATION 2012
(CONSOLIDATED 6 JULY 2023)

Northpower Limited (the 'Company') is required to procure an assurance report by an independent appraiser on the related party transactions of the Company for the disclosure year ended 31 March 2024.

The Auditor-General is the auditor of the Company.

The Auditor-General has appointed me, Silvio Bruinsma, using the staff and resources of Deloitte Limited, to undertake a reasonable assurance engagement, on his behalf, on:

- whether the Company's related party transactions for the disclosure year ended 31 March 2024, comply, in all material respects, with clauses 2.3.6 and 2.3.7 of the Electricity Distribution Information Disclosure Determination 2012 (consolidated 6 July 2023) (the 'Information Disclosure Determination') and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 20 May 2020) (the 'Input Methodologies Determination'); and

- whether the steps taken by the Company, as specified under the "*Description of steps and analysis undertaken by the Company*" are considered to be, in all material respects, reasonable in the circumstances.

Opinion

In our opinion, in all material respects:

- based on the information we have obtained, the related party transactions we have sampled and the analysis we have undertaken, the Company's related party transactions for the disclosure year ended 31 March 2024, comply with clauses 2.3.6 and 2.3.7 of the Information Disclosure Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Input Methodologies Determination; and

- the steps taken by the Company, as specified under the "*Description of steps and analysis undertaken by the Company*" are considered to be reasonable in the circumstances.

Basis for opinion

We conducted our engagement in accordance with the Standard on Assurance Engagements (SAE) 3100 (Revised) *Compliance Engagements* ("SAE 3100 (Revised)"), issued by the New Zealand Auditing and Assurance Standards Board. An engagement conducted in accordance with SAE 3100 (Revised) requires that we comply with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information*.

We have obtained sufficient recorded evidence and explanations that we required to provide a basis for our opinion.

The key assumptions we made in carrying out our work

In carrying out our work we have assumed that the Company's internal controls that we tested, and placed reliance on, during our audit of the financial statements for the year ended 31 March 2024 also applied in relation to our work as the independent appraiser for the disclosure year ended 31 March 2024.

Notwithstanding the aforementioned assumption, we have carried out specific tests to assess if the Company has identified related parties and related party transactions during the disclosure year ended 31 March 2024.

Deloitte.

How we sampled the Company's related party transactions

For the material related-parties who provided, or acquired, a material value of goods and services to or from the Company, we selected a small sample of related-party transactions to assess if they had been valued in accordance with the requirements of the Information Disclosure Determination and the Input Methodologies Determination.

Description of steps and analysis undertaken by the Company

The process to ensure transactions were on an arm's length basis are set out in Northpower Limited's Network Procurement policy for Related Parties.

Methods available to be used include any or all of the following depending on the nature of the proposed transaction, the information reasonably available and what is practicable in the circumstances given the market for the relevant services:

- Conducting a tendering process for the goods or services (not utilised during the 31 March 2024 disclosure year);
- Undertaking internal benchmarking of the related party transactions against substantially same goods or services provided by the related party to its other customers (utilised for the majority of transactions during the 31 March 2024 disclosure year);
- Undertaking internal benchmarking of the related party transactions against substantially same goods or services provided by similar external providers (not utilised during the 31 March 2024 disclosure year);
- Commissioning a third party to undertake market benchmarking of the prices of substantially similar goods or services (not utilised during the 31 March 2024 disclosure year); and
- Engaging an expert to undertake an independent valuation to determine market value of the goods or service (not utilised during the 31 March 2024 disclosure year).

To further assess whether the Service level agreement, and other related party transactions, were at arm's length, an internal benchmarking review was completed. The rates applied, in the Service Level Agreement with Northpower Contracting Limited, were compared to rates agreed in third party service level agreements for similar work.

Directors' responsibilities

The directors of the Company are responsible for:

- the identification of related-parties and related-party transactions during the disclosure year ended 31 March 2024; and
- the valuation of goods and services acquired from or supplied to a related party, in accordance with the requirements of the Information Disclosure Determination and the Input Methodologies Determination.

The directors of the Company are also responsible for the identification of risks that may threaten compliance with the schedules and clauses identified above and controls which will mitigate those risks and monitor ongoing compliance.

Auditor's responsibilities

Our responsibility is to prepare a report that provides reasonable assurance on whether:

- the Company's related party transactions for the disclosure year ended 31 March 2024, comply, in all material respects, with clauses 2.3.6 and 2.3.7 of the Information Disclosure Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Input Methodologies Determination; and
- the steps taken by the Company, as specified under the "*Description of steps and analysis undertaken by the Company*" are considered to be, in all material respects, reasonable in the circumstances.

An assurance engagement to report on the Company's compliance with the Information Disclosure Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements. The procedures selected depend on our judgement, including the identification and assessment of the risks of material non-compliance with the requirements.

Deloitte.

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error, or non-compliance may occur and not be detected.

We did not examine every related party transaction, nor do we guarantee complete accuracy of the related-party disclosures.

A reasonable assurance engagement throughout the disclosure year does not provide assurance on whether compliance will continue in the future.

Restricted use

This report has been prepared for your exclusive use in accordance with clause 2.8.4 of the Information Disclosure Determination and is provided solely for the purpose of establishing whether the compliance requirements have been met. We disclaim any assumption of responsibility for any reliance on this report to any person other than you, or for any other purpose than that for which it was prepared.

Independence and quality control

We complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the requirements of Professional and Ethical Standard 1 International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand) (PES 1) issued by the New Zealand Auditing and Assurance Standards Board; and

- quality management requirements, which incorporate Professional and Ethical Standard 3 Quality Management for Firms that perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements (PES 3) issued by the New Zealand Auditing and Assurance Standards Board. PES 3 requires our firm to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

The Auditor-General, and his employees, and Deloitte Limited and its partners and 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 trading activities of the company, this engagement, other regulatory engagements, and the annual audit of the company's financial statements, we have no relationship with or interests in the company or its subsidiaries.

Silvio Bruinsma

Silvio Bruinsma
Deloitte Limited
On behalf of the Auditor-General
Auckland, New Zealand
28 August 2024