EDB Information Disclosure Requirements
Information Templates

Schedules 1–10
excluding 5f–5h

Company Name	EA Networks
Disclosure Date	29 August 2024
Disclosure Year (year ended)	31 March 2024

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

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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 references.

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	**EA Networks**
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

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	24,339	732	89,587	4,891	25,532
Network	6,794	204	25,008	1,365	7,127
Non-network	17,545	528	64,579	3,525	18,405
Expenditure on assets	26,116	786	96,126	5,247	27,396
Network	25,260	760	92,979	5,076	26,499
Non-network	855	26	3,148	172	897

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	74,054	2,228
Standard consumer line charge revenue	74,054	2,228
Non-standard consumer line charge revenue	–	–

1(iii): Service intensity measures

Demand density	55	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	201	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	7	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	30,085	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	15,454	33.81%
Pass-through and recoverable costs excluding financial incentives and wash-ups	10,880	23.80%
Total depreciation	12,409	27.15%
Total revaluations	13,749	30.08%
Regulatory tax allowance	246	0.54%
Regulatory profit/(loss) including financial incentives and wash-ups	20,472	44.78%
Total regulatory income	45,712	

1(v): Reliability

Interruption rate	18.32	*Interruptions per 100 circuit km*

Company Name	**EA Networks**
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		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8				
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	9.45%	8.40%	5.54%
11	Excluding revenue earned from financial incentives	9.77%	8.76%	5.51%
12	Excluding revenue earned from financial incentives and wash-ups	9.64%	8.64%	5.39%
13				
14	**Mid-point estimate of post tax WACC**	3.52%	4.88%	6.05%
15	25th percentile estimate	2.84%	4.20%	5.37%
16	75th percentile estimate	4.20%	5.56%	6.73%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	9.75%	8.91%	6.24%
21	Excluding revenue earned from financial incentives	10.07%	9.28%	6.21%
22	Excluding revenue earned from financial incentives and wash-ups	9.94%	9.15%	6.09%
23				
24	**WACC rate used to set regulatory price path**	4.57%	4.57%	4.57%
25				
26	**Mid-point estimate of vanilla WACC**	3.82%	5.39%	6.75%
27	25th percentile estimate	3.14%	4.71%	6.07%
28	75th percentile estimate	4.50%	6.07%	7.43%
29				

sch ref					
30	**2(ii): Information Supporting the ROI**			**($000)**	
31					
32		Total opening RAB value	343,290		
33	*plus*	Opening deferred tax	(17,375)		
34	**Opening RIV**			325,915	
35					
36	**Line charge revenue**			47,020	
37					
38		Expenses cash outflow	26,334		
39	*add*	Assets commissioned	17,086		
40	*less*	Asset disposals	1,374		
41	*add*	Tax payments	(1,074)		
42	*less*	Other regulated income	(1,308)		
43	**Mid-year net cash outflows**			42,280	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	360,224		
48	*less*	Adjustment resulting from asset allocation	(118)		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(18,695)		
51	**Closing RIV**			341,647	
52					
53	**ROI – comparable to a vanilla WACC**				6.24%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			5.97%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				5.54%
60					

Company Name	**EA Networks**
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

61

2(iii): Information Supporting the Monthly ROI

62

63	**Opening RIV**	N/A

64

65

sch ref		Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
66							
67	April						–
68	May						–
69	June						–
70	July						–
71	August						–
72	September						–
73	October						–
74	November						–
75	December						–
76	January						–
77	February						–
78	March						–
79	**Total**	–	–	–	–	–	–

80		
81	**Tax payments**	N/A
82		
83	**Term credit spread differential allowance**	N/A
84		
85	**Closing RIV**	N/A
86		
87		
88	**Monthly ROI – comparable to a vanilla WACC**	N/A
89		
90	**Monthly ROI – comparable to a post tax WACC**	N/A
91		

92

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

93		
94	**Year-end ROI – comparable to a vanilla WACC**	5.92%
95		
96	**Year-end ROI – comparable to a post tax WACC**	5.21%
97		

98 ** 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.*

99

100

2(v): Financial Incentives and Wash-Ups

101			
102	IRIS incentive adjustment	137	
103	Purchased assets – avoided transmission charge		
104	Energy efficiency and demand incentive allowance		
105	Quality incentive adjustment	17	
106	Other financial incentives		
107	**Financial incentives**		154
108			
109	**Impact of financial incentives on ROI**		0.03%
110			
111	Input methodology claw-back		
112	CPP application recoverable costs		
113	Catastrophic event allowance		
114	Capex wash-up adjustment	532	
115	Transmission asset wash-up adjustment		
116	2013–15 NPV wash-up allowance		
117	Reconsideration event allowance		
118	Other wash-ups		
119	**Wash-up costs**		532
120			
121	**Impact of wash-up costs on ROI**		0.12%

Company Name	**EA Networks**
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

sch ref			
7		**3(i): Regulatory Profit**	**($000)**
8		**Income**	
9		Line charge revenue	47,020
10	*plus*	Gains / (losses) on asset disposals	(1,259)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	(49)
12			
13		**Total regulatory income**	45,712
14		**Expenses**	
15	*less*	Operational expenditure	15,454
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	10,880
18			
19		**Operating surplus / (deficit)**	19,378
20			
21	*less*	Total depreciation	12,409
22			
23	*plus*	Total revaluations	13,749
24			
25		**Regulatory profit / (loss) before tax**	20,718
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	246
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	20,472
32			

sch ref			
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34	**Pass through costs**		
35	Rates	253	
36	Commerce Act levies	166	
37	Industry levies	120	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	10,285	
41	Transpower new investment contract charges	56	
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**		10,880
47			

sch ref		
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	**EA Networks**
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

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

sch ref			RAB 31 Mar 20 ($000)	RAB 31 Mar 21 ($000)	RAB 31 Mar 22 ($000)	RAB 31 Mar 23 ($000)	RAB 31 Mar 24 ($000)
10		**Total opening RAB value**	268,447	292,650	300,961	321,934	343,290
11							
12	*less*	**Total depreciation**	9,990	10,649	10,873	11,591	12,409
13							
14	*plus*	**Total revaluations**	6,771	4,429	20,799	21,377	13,749
15							
16	*plus*	**Assets commissioned**	29,987	15,501	11,600	12,049	17,086
17							
18	*less*	**Asset disposals**	1,095	976	444	522	1,374
19							
20	*plus*	**Lost and found assets adjustment**	–	–	–	–	–
21							
22	*plus*	**Adjustment resulting from asset allocation**	(1,470)	6	(109)	43	(118)
23							
24		**Total closing RAB value**	292,650	300,961	321,934	343,290	360,224
25							

4(ii): Unallocated Regulatory Asset Base

sch ref			Unallocated RAB *		RAB	
28			($000)	($000)	($000)	($000)
29		**Total opening RAB value**		345,807		343,290
30	*less*					
31		**Total depreciation**		12,560		12,409
32	*plus*					
33		**Total revaluations**		13,850		13,749
34	*plus*					
35		Assets commissioned (other than below)	11,459		11,390	
36		Assets acquired from a regulated supplier	–		–	
37		Assets acquired from a related party	5,696		5,696	
38		**Assets commissioned**		17,155		17,086
39	*less*					
40		Asset disposals (other than below)	1,374		1,374	
41		Asset disposals to a regulated supplier	–		–	
42		Asset disposals to a related party	–		–	
43		**Asset disposals**		1,374		1,374
44						
45	*plus*	**Lost and found assets adjustment**				
46						
47	*plus*	**Adjustment resulting from asset allocation**				(118)
48						
49		**Total closing RAB value**		362,878		360,224

** 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.* *50*

Company Name **EA Networks**
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

sch ref						
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	345,807		343,290	
61	*less*	Opening value of fully depreciated, disposed and lost assets	1,535		1,531	
62						
63		Total opening RAB value subject to revaluation	344,272		341,759	
64		**Total revaluations**		13,850		13,749
65						

66 4(iv): Roll Forward of Works Under Construction

sch ref			**Unallocated works under construction**		**Allocated works under construction**	
67						
68		**Works under construction—preceding disclosure year**		9,501		9,501
69	*plus*	Capital expenditure	16,102		16,101	
70	*less*	Assets commissioned	17,155		17,086	
71	*plus*	Adjustment resulting from asset allocation			(69)	
72		**Works under construction - current disclosure year**		8,448		8,447
73						
74		Highest rate of capitalised finance applied				–
75						

Company Name **EA Networks**
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SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

This schedule requires information on the calculation of the Regulatory Asset Base (RAB) value to the end of this disclosure year. This informs the ROI calculation in Schedule 2.
EDBs must provide explanatory comment on the value of their RAB in Schedule 14 (Mandatory Explanatory Notes). This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

4(v): Regulatory Depreciation

sch ref		Unallocated RAB *		RAB	
78		**($000)**	**($000)**	**($000)**	**($000)**
79	Depreciation - standard	11,060		11,060	
80	Depreciation - no standard life assets	1,500		1,349	
81	Depreciation - modified life assets	–		–	
82	Depreciation - alternative depreciation in accordance with CPP	–		–	
83	**Total depreciation**		12,560		12,409

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*

4(vii): Disclosure by Asset Category

($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**	16,343	3,854	30,552	55,256	96,261	75,162	39,276	2,740	23,846	343,290
100	*less*	Total depreciation	600	94	1,252	2,203	2,412	2,429	1,830	240	1,349	12,409
101	*plus*	Total revaluations	657	155	1,226	2,205	3,873	3,012	1,553	110	958	13,749
102	*plus*	Assets commissioned	817	179	427	2,580	7,353	3,935	1,244	299	252	17,086
103	*less*	Asset disposals	3	–	–	435	–	291	645	–	–	1,374
104	*plus*	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
105	*plus*	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	(118)	(118)
106	*plus*	Asset category transfers	–	–	–	–	–	–	–	–	–	–
107		**Total closing RAB value**	17,214	4,094	30,953	57,403	105,075	79,389	39,598	2,909	23,589	360,224
108												
109		**Asset Life**										
110		Weighted average remaining asset life	32.8	47.0	32.7	30.0	43.9	35.1	25.0	12.8	20.1	(years)
111		Weighted average expected total asset life	45.1	55.0	44.9	45.9	55.1	45.0	36.6	15.7	24.9	(years)

Company Name **EA Networks**
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**		20,718	
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	48		*
12		Amortisation of initial differences in asset values	2,068		
13		Amortisation of revaluations	2,739		
14				4,855	
15					
16	*less*	Total revaluations	13,749		
17		Income included in regulatory profit / (loss) before tax but not taxable			*
18		Discretionary discounts and customer rebates	3,006		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax			*
20		Notional deductible interest	7,938		
21				24,693	
22					
23		**Regulatory taxable income**		879	
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income		879	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		246	
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	47,556		
37	*less*	Amortisation of initial differences in asset values	2,068		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	495		
40		Closing unamortised initial differences in asset values		44,993	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		23	
43					

Company Name	**EA Networks**
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	273,613	
48		Adjusted depreciation	9,670	
49		Total depreciation	12,409	
50		Amortisation of revaluations		2,739
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**	(17,375)	
62	*plus*	Tax effect of adjusted depreciation	2,708	
64	*less*	Tax effect of tax depreciation	3,467	
66	*plus*	Tax effect of other temporary differences*	(268)	
68	*less*	Tax effect of amortisation of initial differences in asset values	579	
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	(255)	
74	*plus*	Deferred tax cost allocation adjustment	31	
76		**Closing deferred tax**		(18,695)
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**	154,927	
84	*less*	Tax depreciation	12,383	
85	*plus*	Regulatory tax asset value of assets commissioned	17,086	
86	*less*	Regulatory tax asset value of asset disposals	463	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	(6)	
89	*plus*	Other adjustments to the RAB tax value	(2,495)	
90		**Closing sum of regulatory tax asset values**		156,666

Company Name	**EA Networks**
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

		($000)	($000)	
7	**5b(i): Summary—Related Party Transactions**			
8	**Total regulatory income**		81	
9				
10	**Market value of asset disposals**		–	
11				
12	Service interruptions and emergencies	368		
13	Vegetation management	53		
14	Routine and corrective maintenance and inspection	1,194		
15	Asset replacement and renewal (opex)	791		
16	**Network opex**		2,406	
17	Business support	473		
18	System operations and network support - other	134		
19	Non-network solutions provided by a related party or third party	–		*Not Required before DY2025*
20	**Operational expenditure**		3,013	
21	Consumer connection	1,369		
22	System growth	1,225		
23	Asset replacement and renewal (capex)	2,730		
24	Asset relocations	6		
25	Quality of supply	7		
26	Legislative and regulatory	–		
27	Other reliability, safety and environment	216		
28	**Expenditure on non-network assets**		149	
29	**Expenditure on assets**		5,702	
30	Cost of financing			
31	Value of capital contributions		6	
32	Value of vested assets			
33	**Capital Expenditure**		5,696	
34	**Total expenditure**		8,709	
35				
36	**Other related party transactions**		1,156	

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

	Name of related party	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
38			
39	EA Networks Field Services	Asset replacement and renewal (opex)	790
40	EA Networks Field Services	Business support	88
41	EA Networks Field Services	Routine and corrective maintenance and inspection	1,194
42	EA Networks Field Services	Service interruptions and emergencies	367
43	EA Networks Field Services	System operations and network support - other	120
44	EA Networks Field Services	Vegetation management	53
45	EA Networks Field Services	Asset relocations	6
46	EA Networks Field Services	Asset replacement and renewal (capex)	2,520
47	EA Networks Field Services	Consumer connection	1,366
48	EA Networks Field Services	Expenditure on non-network assets	97
49	EA Networks Field Services	Other reliability, safety and environment	216
50	EA Networks Field Services	Quality of supply	7
51	EA Networks Field Services	System growth	609
52	Ashburton Contracting Ltd	Asset replacement and renewal (capex)	210
53	Ashburton Contracting Ltd	Asset replacement and renewal (opex)	1
54	Ashburton Contracting Ltd	Consumer connection	3
55	Ashburton Contracting Ltd	Service interruptions and emergencies	1
56	Ashburton Contracting Ltd	System growth	616
57	Ashburton District Council	Business support	39
58	Electraserve	Business support	3
59	Electraserve	Expenditure on non-network assets	52
60	Directors	Business support	336
61	Enviro-Mark Solutions	Business support	7
62	Orion Group	System operations and network support - other	14
63	**Total value of related party transactions**		8,715
64	** include additional rows if needed*		

Company Name	**EA Networks**
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			
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	**EA Networks**
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

sch ref			Value allocated ($000s)			
8		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
9						
10	**Service interruptions and emergencies**					
11	Directly attributable		742			
12	Not directly attributable	–	–	–	–	–
13	**Total attributable to regulated service**		742			
14	**Vegetation management**					
15	Directly attributable		1,081			
16	Not directly attributable	–	–	–	–	–
17	**Total attributable to regulated service**		1,081			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		1,336			
20	Not directly attributable	–	–	–	–	–
21	**Total attributable to regulated service**		1,336			
22	**Asset replacement and renewal**					
23	Directly attributable		1,155			
24	Not directly attributable	–	–	–	–	–
25	**Total attributable to regulated service**		1,155			
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		4,161			
32	Not directly attributable	–	–	–	–	–
33	**Total attributable to regulated service**		4,161			
34	**Business support**					
35	Directly attributable		595			
36	Not directly attributable	–	6,384	1,153	7,537	–
37	**Total attributable to regulated service**		6,979			
38						
39	**Operating costs directly attributable**		9,070			
40	**Operating costs not directly attributable**	–	6,384	1,153	7,537	–
41	**Operational expenditure**		15,454			
42						

Company Name	**EA Networks**
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			
43	**5d(ii): Other Cost Allocations**		
44	**Pass through and recoverable costs**		**($000)**
45	**Pass through costs**		
46	Directly attributable		539
47	Not directly attributable		–
48	**Total attributable to regulated service**		539
49	**Recoverable costs**		
50	Directly attributable		10,341
51	Not directly attributable		–
52	**Total attributable to regulated service**		10,341
53			

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

sch ref				**CY-1**	**Current Year (CY)**
54					
55				**($000)**	
56	**Change in cost allocation 1**			**CY-1**	**Current Year (CY)**
57	Cost category		Original allocation		
58	Original allocator or line items		New allocation		
59	New allocator or line items		Difference	–	–
60					
61	Rationale for change				
62					
63					
64				**($000)**	
65	**Change in cost allocation 2**			**CY-1**	**Current Year (CY)**
66	Cost category		Original allocation		
67	Original allocator or line items		New allocation		
68	New allocator or line items		Difference	–	–
69					
70	Rationale for change				
71					
72					
73				**($000)**	
74	**Change in cost allocation 3**			**CY-1**	**Current Year (CY)**
75	Cost category		Original allocation		
76	Original allocator or line items		New allocation		
77	New allocator or line items		Difference	–	–
78					
79	Rationale for change				
80					
81					
82	** a change in cost allocation must be completed for each cost allocator change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or component.*				
83	*† include additional rows if needed*				

Company Name **EA Networks**
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	17,214
12	Not directly attributable	–
13	**Total attributable to regulated service**	17,214
14	**Subtransmission cables**	
15	Directly attributable	4,094
16	Not directly attributable	–
17	**Total attributable to regulated service**	4,094
18	**Zone substations**	
19	Directly attributable	30,953
20	Not directly attributable	–
21	**Total attributable to regulated service**	30,953
22	**Distribution and LV lines**	
23	Directly attributable	57,403
24	Not directly attributable	–
25	**Total attributable to regulated service**	57,403
26	**Distribution and LV cables**	
27	Directly attributable	105,075
28	Not directly attributable	–
29	**Total attributable to regulated service**	105,075
30	**Distribution substations and transformers**	
31	Directly attributable	79,389
32	Not directly attributable	–
33	**Total attributable to regulated service**	79,389
34	**Distribution switchgear**	
35	Directly attributable	39,598
36	Not directly attributable	–
37	**Total attributable to regulated service**	39,598
38	**Other network assets**	
39	Directly attributable	2,907
40	Not directly attributable	2
41	**Total attributable to regulated service**	2,909
42	**Non-network assets**	
43	Directly attributable	16,591
44	Not directly attributable	6,998
45	**Total attributable to regulated service**	23,589
46		
47	**Regulated service asset value directly attributable**	353,224
48	**Regulated service asset value not directly attributable**	7,000
49	**Total closing RAB value**	360,224
50		

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

sch ref				($000) CY-1	($000) 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	–	–
57					
58	Rationale for change				
59					
60					
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	–	–
66					
67	Rationale for change				
68					
69					
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	–	–
75					
76	Rationale for change				
77					
78					

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	**EA Networks**
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

sch ref			($000)	($000)
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		5,028
9		System growth		380
10		Asset replacement and renewal		9,793
11		Asset relocations		9
12		Reliability, safety and environment:		
13		Quality of supply	482	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	347	
16		**Total reliability, safety and environment**		829
17		**Expenditure on network assets**		16,039
18		Expenditure on non-network assets		543
19				
20		**Expenditure on assets**		16,582
21	*plus*	Cost of financing		
22	*less*	Value of capital contributions		481
23	*plus*	Value of vested assets		
24				
25		**Capital expenditure**		16,101

sch ref		
26	**6a(ii): Subcomponents of Expenditure on Assets (where known)**	**($000)**
27	Energy efficiency and demand side management, reduction of energy losses	
28	Overhead to underground conversion	3,921
29	Research and development	

sch ref				
31		**6a(iii): Consumer Connection**		
32		*Consumer types defined by EDB**	**($000)**	**($000)**
33		Industry/Large connection	872	
		New subdivision	2,102	
		Urban with transformer	64	
		Urban without transformer	258	
		Rural with transformer	652	
34		Rural without transformer	317	
35		Tariff group change	312	
36		Safety	321	
37		Other	130	
38		** include additional rows if needed*		
39		**Consumer connection expenditure**		5,028
40				
41	*less*	Capital contributions funding consumer connection expenditure	481	
42		**Consumer connection less capital contributions**		4,547

sch ref				
43		**6a(iv): System Growth and Asset Replacement and Renewal**		
44 *45*			**System Growth ($000)**	**Asset Replacement and Renewal ($000)**
46		Subtransmission	16	–
47		Zone substations	–	220
48		Distribution and LV lines	17	3,118
49		Distribution and LV cables	85	2,297
50		Distribution substations and transformers	7	2,365
51		Distribution switchgear	158	1,677
52		Other network assets	97	116
53		**System growth and asset replacement and renewal expenditure**	380	9,793
54	*less*	Capital contributions funding system growth and asset replacement and renewal		
55		**System growth and asset replacement and renewal less capital contributions**	380	9,793
56				

sch ref				
57		**6a(v): Asset Relocations**		
58		*Project or programme**	**($000)**	**($000)**
59				
60				
61				
62				
63				
64		** include additional rows if needed*		
65		All other projects or programmes - asset relocations	9	
66		**Asset relocations expenditure**		9
67	*less*	Capital contributions funding asset relocations		
68		**Asset relocations less capital contributions**		9

Company Name	**EA Networks**
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				
69				
70		**6a(vi): Quality of Supply**		
71		*Project or programme**	**($000)**	**($000)**
72		22kV Conversion - Methven Hwy Springfield	437	
73				
74				
75				
76				
77		** include additional rows if needed*		
78		All other projects programmes - quality of supply	45	
79		**Quality of supply expenditure**		482
80	*less*	Capital contributions funding quality of supply		
81		**Quality of supply less capital contributions**		482
82		**6a(vii): Legislative and Regulatory**		
83		*Project or programme**	**($000)**	**($000)**
84				
85				
86				
87				
88				
89		** include additional rows if needed*		
90		All other projects or programmes - legislative and regulatory		
91		**Legislative and regulatory expenditure**		–
92	*less*	Capital contributions funding legislative and regulatory		
93		**Legislative and regulatory less capital contributions**		–
94		**6a(viii): Other Reliability, Safety and Environment**		
95		*Project or programme**	**($000)**	**($000)**
96		Safety	333	
97				
98				
99				
100				
101		** include additional rows if needed*		
102		All other projects or programmes - other reliability, safety and environment	14	
103		**Other reliability, safety and environment expenditure**		347
104	*less*	Capital contributions funding other reliability, safety and environment		
105		**Other reliability, safety and environment less capital contributions**		347
106				
107		**6a(ix): Non-Network Assets**		
108		**Routine expenditure**		
109		*Project or programme**	**($000)**	**($000)**
110		Routine info tech	25	
111		Vehicles	55	
112				
113				
114				
115		** include additional rows if needed*		
116		All other projects or programmes - routine expenditure	59	
117		**Routine expenditure**		139
118		**Atypical expenditure**		
119		*Project or programme**	**($000)**	**($000)**
120		Bunker fire suppression system	170	
121		Comms pole	173	
122		Solar PV for building	61	
123				
124				
125		** include additional rows if needed*		
126		All other projects or programmes - atypical expenditure		
127		**Atypical expenditure**		404
128				
129		**Expenditure on non-network assets**		543

Company Name	**EA Networks**
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				
7	**6b(i): Operational Expenditure** *Required for DY2024 and DY2025 only*		**($000)**	**($000)**
8	Service interruptions and emergencies		742	
9	Vegetation management		1,081	
10	Routine and corrective maintenance and inspection		1,336	
11	Asset replacement and renewal		1,155	
12	**Network opex**			4,314
13	Non-network solutions provided by a related party or third party	*Required for DY2025 only*		
14	System operations and network support		4,161	
15	Business support		6,979	
16	**Non-network opex**			11,140
17				
18	**Operational expenditure**			15,454
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	EA Networks
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	7
42	Direct billing*	–
43	Research and development	3
44	Insurance	479

45 ** Direct billing expenditure by suppliers that directly bill the majority of their consumers*

Company Name **EA Networks**
For Year Ended **31 March 2024**

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	45,901	47,020	2%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	5,268	5,028	(5%)
11	System growth	1,751	380	(78%)
12	Asset replacement and renewal	7,830	9,793	25%
13	Asset relocations	–	9	–
14	Reliability, safety and environment:			
15	Quality of supply	895	482	(46%)
16	Legislative and regulatory	108	–	(100%)
17	Other reliability, safety and environment	392	347	(11%)
18	**Total reliability, safety and environment**	1,395	829	(41%)
19	**Expenditure on network assets**	16,244	16,039	(1%)
20	Expenditure on non-network assets	917	543	(41%)
21	Expenditure on assets	17,161	16,582	(3%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,488	742	(50%)
24	Vegetation management	831	1,081	30%
25	Routine and corrective maintenance and inspection	1,051	1,336	27%
26	Asset replacement and renewal	1,328	1,155	(13%)
27	**Network opex**	4,698	4,314	(8%)
28	Non-network solutions provided by a related party or third party *Not Required before DY2025*		–	–
29	System operations and network support	7,826	4,161	(47%)
30	Business support	8,202	6,979	(15%)
31	**Non-network opex**	16,028	11,140	(30%)
32	**Operational expenditure**	20,726	15,454	(25%)
33	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
34	Energy efficiency and demand side management, reduction of energy losses	71	–	(100%)
35	Overhead to underground conversion	3,158	3,921	24%
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	–	7	–
40	Direct billing	–	–	–
41	Research and development	–	3	–
42	Insurance	377	479	27%
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	**EA Networks**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	**Total Network**

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(i): Billed Quantities by Price Component

Billed quantities by price component *Not Required after DY2024*

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)	Price component	Fixed daily charge	Capacity Charge	Booked capacity charge	Fixtures	Anytime supply	Controlled 16h supply	Night only supply	Night boost supply	Weekdays supply	Nights & weekends supply	Anytime injection
					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	Cons	kW	kVA	Fixtures	kWh	kWh	kWh	kWh	kWh	kWh	kWh
General Supply - 8 kVA	Residential and commercial	Standard	225	661		261	–	–	–	500,948	128,833	6,675	2,073	10,309	11,987	6,916
General Supply - 20 kVA	Residential and commercial	Standard	16,291	128,780		16,028	–	–	21	95,330,353	28,840,414	3,200,142	666,666	329,609	412,630	1,109,751
General Supply - 50 kVA	Residential and commercial	Standard	1,778	30,120		1,741	–	–	1	27,546,911	1,907,560	317,451	93,272	173,298	81,109	317,024
General Supply - 100 kVA	Commercial	Standard	799	66,502		798	–	–	16	65,773,660	597,809	127,218	2,898	–	–	226,410
General Supply - 150 kVA	Commercial	Standard	302	47,482		299	–	–	–	47,335,298	132,055	15,030	–	–	–	630,276
Irrigation	Irrigation	Standard	1,644	238,228		–	141,948	–	–	238,228,021	–	–	–	–	–	–
Industrial	Industrial	Standard	41	35,949		42	–	16,691	–	35,949,125	–	–	–	–	–	–
Industrial HV	Industrial	Standard	2	24		–	–	56	–	23,923	–	–	–	–	–	–
Large Users	Industrial	Standard	10	85,491		8	–	35,960	–	85,490,563	–	–	–	–	–	–
Generation	Generation	Standard	4	–		4	–	–	–	–	–	–	–	–	–	121,288,849
Street Lighting	Public streetlighting	Standard	9	1,064		–	–	–	3,824	1,064,387	–	–	–	–	–	–
differences	NA	Standard	–	643		–	–	–	–	642,912	–	–	–	–	–	188,706
Add extra rows for additional consumer groups or price category codes as necessary																
		Standard consumer totals	21,105	634,944		19,181	141,948	52,707	3,862	597,886,101	31,606,671	3,666,516	764,909	513,216	505,726	123,767,932
		Non-standard consumer totals	–	–		–	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	21,105	634,944		19,181	141,948	52,707	3,862	597,886,101	31,606,671	3,666,516	764,909	513,216	505,726	123,767,932

Company Name	**EA Networks**
For Year Ended	**31 March 2024**
Network / Sub-Network Name	**Total Network**

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.

31
8(ii): Line Charge Revenues ($000) by Price Component

32
33

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

35							**Price component**	Fixed daily charge	Capacity Charge	Booked capacity charge	Fixtures	Anytime supply	Controlled 16h supply	Night only supply	Night boost supply	Weekdays supply	Nights & weekends supply	Anytime injection
36	**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**	**Total transmission line charge revenue**	**Rate (eg, $ per day, $ per kWh, etc.)**	$/con/day	$/kW/day	$/kVA/day	$/fixture/day	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
37					*Not Required after D*	*Not Required after DY2024*												
38	General Supply - 8 kVA	Residential and commercial	Standard	$71	53	18		$32	–	–	–	$35	$3	–	–	$1	–	–
39	General Supply - 20 kVA	Residential and commercial	Standard	$9,896	8,079	1,817		$2,640	–	–	$2	$6,578	$577	$48	$13	$33	$6	–
40	General Supply - 50 kVA	Residential and commercial	Standard	$2,650	2,177	473		$686	–	–	–	$1,901	$38	$5	$2	$17	$1	–
41	General Supply - 100 kVA	Commercial	Standard	$5,323	4,551	772		$770	–	–	$1	$4,538	$12	$2	–	–	–	–
	General Supply - 150 kVA	Commercial	Standard	$3,780	3,257	523		$512	–	–	–	$3,266	$3	–	–	–	–	–
	Irrigation	Irrigation	Standard	$20,919	15,355	5,564		–	$20,921	–	–	–	–	–	–	–	–	–
42	Industrial	Industrial	Standard	$1,451	1,100	351		$73	–	$1,378	–	–	–	–	–	–	–	–
43	Industrial HV	Industrial	Standard	$4	3	1		–	–	$4	–	–	–	–	–	–	–	–
44	Large Users	Industrial	Standard	$2,166	1,138	1,028		$29	–	$2,136	–	–	–	–	–	–	–	–
45	Generation	Generation	Standard	$554	553	1		$555	–	–	–	–	–	–	–	–	–	–
46	Street Lighting	Public streetlighting	Standard	$213	208	5		–	–	–	$213	–	–	–	–	–	–	–
47	differences	NA	Standard	($7)	(7)	–		–	–	–	–	($7)	–	–	–	–	–	–
48	*Add extra rows for additional consumer groups or price category codes as necessary*																	
49			**Standard consumer totals**	$47,020	$36,467	$10,553		$5,297	$20,921	$3,518	$216	$16,311	$633	$55	$15	$51	$7	–
50			**Non-standard consumer totals**	–	–	–		–	–	–	–	–	–	–	–	–	–	–
51			**Total for all consumers**	$47,020	$36,467	$10,553		$5,297	$20,921	$3,518	$216	$16,311	$633	$55	$15	$51	$7	–

52

53
8(iii): Number of ICPs directly billed

Check OK

54 **Number of directly billed ICPs at year end** –

Company Name **EA Networks**
For Year Ended **31 March 2024**
Network / Sub-network Name **Total Network**

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

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	2,245	2,218	(27)	4
10	All	Overhead Line	Wood poles	No.	25,358	24,900	(458)	4
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	391	383	(8)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	9	8	(1)	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	20	20	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	75	75	–	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	36	36	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	136	135	(1)	3
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	11	11	–	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	189	189	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	N/A
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	31	32	1	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,938	1,920	(18)	4
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	–	–	–	N/A
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	337	345	8	4
39	HV	Distribution Cable	Distribution UG PILC	km	5	4	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	45	61	16	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	2	–	(2)	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	7,679	7,068	(611)	2
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	2	2	4
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	541	554	13	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,586	4,485	(101)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	2,047	2,083	36	4
48	HV	Distribution Transformer	Voltage regulators	No.	1	–	(1)	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	577	591	14	3
50	LV	LV Line	LV OH Conductor	km	58	49	(9)	4
51	LV	LV Cable	LV UG Cable	km	434	452	18	4
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	341	338	(3)	4
53	LV	Connections	OH/UG consumer service connections	No.	20,988	21,218	230	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	827	823	(4)	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	2	2	–	4
58	All	Load Control	Relays	No	400	400	–	1
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**EA Networks**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Total Network**

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**	**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	All	Overhead Line	Concrete poles / steel structure	No.	–	1	2	13	199	518	1,152	–	4	9	59	56	10	–	–	–	1	6	18	36	28	41	–	1	1	7	–	43	12	–	–	1			2,218		4
11	All	Overhead Line	Wood poles	No.	–	73	98	220	359	2,168	6,000	809	565	1,519	1,130	769	818	568	705	1,024	929	610	480	396	393	466	493	499	482	522	560	586	572	447	313	327			24,900		4
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	0	2	37	35	0	58	104	10	11	0	18	8	8	22	13	6	7	5	8	11	10	–	3	–	7	0	1	0	0			383		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	3	0	0	–	0	0	–	0	0	–	–	–	–	–	0	–	1	–	–	–	–	2	0	–	0	1	–			8		4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	–	1	–	5	–	2	–	3	1	2	–	1	1	–	2	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–			20		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–																																		–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	7	–	15	2	2	7	–	7	–	7	–	5	–	4	–	–	–	–	10	1	5	3	–	–	–			75		3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	9	15	12	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			36		4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	5	1	31	2	7	3	22	3	3	3	9	7	–	–	–	–	–	6	–	–	–	6	8	–	8	2	–	1	8			135		3
30	HV	Zone substation switchgear	33kV RMU	No.																																			–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.																																			–		N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	3	2	6	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			11		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	2	11	7	4	–	5	5	27	7	21	11	18	1	–	–	5	–	4	8	8	3	40	2	–	–	–	–	–			189		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.																																			–		N/A
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.		–	1	–	–	2	2	5	–	2	2	–	4	–	–	–	1	–	–	2	1	2	–	–	–	6	1	1	–	–	–	–			32		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km		1	16	32	81	306	543	57	83	132	61	51	36	56	60	59	50	31	23	29	24	27	16	27	11	25	18	24	18	4	13	7			1,920		4
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km																																			–		N/A
38	HV	Distribution Line	SWER conductor	km																																			–		N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km		–	–	0	1	34	27	4	4	5	6	5	4	7	11	6	6	6	11	13	19	7	16	24	26	18	14	11	15	8	25	12			345		4
40	HV	Distribution Cable	Distribution UG PILC	km		–	–	0	3	1	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			4		4
41	HV	Distribution Cable	Distribution Submarine Cable	km																																			–		N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	4	–	2	4	1	2	3	3	1	2	1	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	1	23	12			61		3
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.																																			–		N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	1	7	23	53	59	164	416	46	118	245	321	322	312	279	221	422	562	291	293	305	298	230	209	251	212	46	164	170	175	361	182	310			7,068		3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–			2		N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.		–	–	2	16	48	80	15	10	7	11	11	6	28	16	27	6	28	11	19	19	25	18	12	23	15	10	10	32	12	23	14			554		2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.		6	41	132	196	135	448	180	78	55	182	201	149	181	289	81	255	202	57	228	139	105	125	171	155	41	51	177	131	229	17	48			4,485		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.		–	15	39	118	102	117	7	5	18	20	31	39	70	74	79	118	79	90	111	91	60	124	159	58	82	62	55	58	59	90	53			2,083		4
49	HV	Distribution Transformer	Voltage regulators	No.		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.		–	–	6	40	71	99	14	9	7	3	9	9	14	12	14	8	18	33	15	26	23	22	11	1	20	7	9	28	16	24	23			591		3
51	LV	LV Line	LV OH Conductor	km		1	1	4	3	12	19	1	1	1	1	1	1	0	1	0	0	0	0	0	–	0	0	0	–	0	0	0	0	0	0	0			49		4
52	LV	LV Cable	LV UG Cable	km		–	0	6	22	54	73	8	8	4	7	5	8	12	11	9	11	7	18	10	12	15	16	12	16	18	16	16	15	16	16	11			452		4
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km		0	1	6	18	43	65	7	6	4	4	4	4	6	7	5	7	6	15	7	8	11	11	9	11	13	10	9	12	9	11	9			338		4
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	271	447	412	318	303	308	387	306	324	379	316		17,447	21,218		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	–	–	2	–	1	21	9	6	19	57	1	40	10	–	3	66	14	31	55	145	97	53	77	40	20	34	17	5			823		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single sys	Lot																																		1	1		4
57	All	Capacitor Banks	Capacitors including controls	No		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–		N/A
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	2		4
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	400	400		1
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A

Company Name	**EA Networks**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Total Network**

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)**			
12	> 66kV	–	–	–
13	50kV & 66kV	348	4	352
14	33kV	35	4	39
15	SWER (all SWER voltages)	–	–	–
16	22kV (other than SWER)	1,593	162	1,755
17	6.6kV to 11kV (inclusive—other than SWER)	327	186	513
18	Low voltage (< 1kV)	49	452	501
19	**Total circuit length (for supply)**	2,352	808	3,160
20				
21	Dedicated street lighting circuit length (km)	–	–	–
22	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–
23				

sch ref		Circuit length (km)	(% of total overhead length)
24	**Overhead circuit length by terrain (at year end)**		
25	Urban	71	3%
26	Rural	2,234	95%
27	Remote only	47	2%
28	Rugged only		–
29	Remote and rugged		–
30	Unallocated overhead lines		–
31	**Total overhead length**	2,352	100%
32			

sch ref		Circuit length (km)	(% of total circuit length)
33			
34	Length of circuit within 10km of coastline or geothermal areas (where known)	474	15%
35			

sch ref		Circuit length (km)	(% of total overhead length)	
36				
37	Overhead circuit requiring vegetation management	2,352	100%	*Not required after DY2025*

sch ref		Total newly identified throughout the disclosure year	Total remaining at high risk at the disclosure year-end	
38				
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	
42				
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 **EA Networks**
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	Upper Rakaia embedded network (supplied by Orion)	14	15
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	**EA Networks**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Total Network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

9e(i): Consumer Connections and Decommissionings

Number of ICPs connected during year by consumer type

sch ref	*Consumer types defined by EDB**	**Number of connections (ICPs)**
11	General Supply - 8 kVA	46
12	General Supply - 20 kVA	218
	General Supply - 50 kVA	28
	General Supply - 100 kVA	10
	General Supply - 150 kVA	9
	Street Lighting	–
13	Irrigation	3
14	Industrial Supply	4
15	Industrial Supply HV	1
16	** include additional rows if needed*	
17	**Connections total**	319

Number of ICPs decommissioned during year by consumer type

sch ref	*Consumer types defined by EDB**	**Number of decommissionings**
21	General Supply - 8 kVA	7
	General Supply - 20 kVA	58
	General Supply - 50 kVA	15
	General Supply - 100 kVA	4
22	General Supply - 150 kVA	2
23	Irrigation	4
24	Industrial Supply	2
25	* include additional rows if needed	–
26	** include additional rows if needed*	
27	**Decommissionings total**	92

Distributed generation

sch ref			
30	Number of connections made in year	105	**connections**
31	Capacity of distributed generation installed in year	1.39	**MVA**

9e(ii): System Demand

sch ref			**Demand at time of maximum coincident demand (MW)**
36		**Maximum coincident system demand**	
37		GXP demand	172
38	*plus*	Distributed generation output at HV and above	1
39		**Maximum coincident system demand**	172
40	*less*	Net transfers to (from) other EDBs at HV and above	(0)
41		**Demand on system for supply to consumers' connection points**	173

sch ref			**Energy (GWh)**	
42		**Electricity volumes carried**		
43		Electricity supplied from GXPs	550	
44	*less*	Electricity exports to GXPs	–	
45	*plus*	Electricity supplied from distributed generation	124	
46	*less*	Net electricity supplied to (from) other EDBs	(0)	
47		**Electricity entering system for supply to consumers' connection points**	674	
48	*less*	Total energy delivered to ICPs	635	
49		**Electricity losses (loss ratio)**	39	5.8%
51		**Load factor**	0.45	

9e(iii): Transformer Capacity

sch ref		**(MVA)**
54	Distribution transformer capacity (EDB owned)	605
55	Distribution transformer capacity (Non-EDB owned)	12
56	**Total distribution transformer capacity**	617

sch ref		**(MVA)**
59	Zone substation transformer capacity (EDB owned)	326
60	Zone substation transformer capacity (Non-EDB owned)	34
61	**Total zone substation transformer capacity**	360

Company Name	**EA Networks**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Total Network**

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

8 ## 10(i): Interruptions

sch ref		Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	294
12	Class C (unplanned interruptions on the network)	282
13	Class D (unplanned interruptions by Transpower)	–
14	Class E (unplanned interruptions of EDB owned generation)	–
15	Class F (unplanned interruptions of generation owned by others)	–
16	Class G (unplanned interruptions caused by another disclosing entity)	3
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	579
20		

sch ref		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	216	66
23			

sch ref		SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.4052	112.01
27	Class C (unplanned interruptions on the network)	1.1664	59.28
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	0.0020	2.95
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	1.5736	174.24
35			

sch ref		Normalised SAIFI	Normalised SAIDI	
36	**Normalised SAIFI and SAIDI**			
37	Classes B & C (interruptions on the network)	1.5715	171.29	*Not required after DY2024*
38				

sch ref		SAIFI	SAIDI
39	**Transitional SAIFI and SAIDI (previous method)**		
40	Class B (planned interruptions on the network)	0.4052	112.01
41	Class C (unplanned interruptions on the network)	1.1133	59.28
42			

43 *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	**EA Networks**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Total Network**

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.

44
10(ii): Class C Interruptions and Duration by Cause

		SAIFI	SAIDI	
46	**Cause**			
47	Lightning	0.0292	4.26	
48	Vegetation	0.1618	14.33	
49	Adverse weather	0.0247	2.88	
50	Adverse environment			
51	Third party interference	0.1869	7.62	
52	Wildlife	0.1005	4.37	
53	Human error	0.2755	0.77	
54	Defective equipment	0.2557	18.14	
55	Cause unknown	0.1321	6.90	*Not required after DY2024*
56	Other cause			*Not required before DY2025*
57	Unknown			*Not required before DY2025*
58				
59	**Breakdown of third party interference**	**SAIFI**	**SAIDI**	
60	Dig-in	0.0008	0.13	
61	Overhead contact	0.0377	1.99	
62	Vandalism	0.0024	0.11	
63	Vehicle damage	0.1193	4.74	
64	Other	0.0267	0.65	
65				
66	**Breakdown of vegetation interruptions (vegetation cause)**	**SAIFI**	**SAIDI**	
67	In-zone			*Not required before DY2026*
68	Out-of-zone			*Not required before DY2026*
69				

70
10(iii): Class B Interruptions and Duration by Main Equipment Involved

		SAIFI	SAIDI
72	**Main equipment involved**		
73	Subtransmission lines	0.0228	7.60
74	Subtransmission cables	–	–
75	Subtransmission other	–	–
76	Distribution lines (excluding LV)	0.3723	102.39
77	Distribution cables (excluding LV)	0.0101	2.02
78	Distribution other (excluding LV)	–	–

79
10(iv): Class C Interruptions and Duration by Main Equipment Involved

		SAIFI	SAIDI
81	**Main equipment involved**		
82	Subtransmission lines	0.4259	4.38
83	Subtransmission cables	–	–
84	Subtransmission other	–	–
85	Distribution lines (excluding LV)	0.6873	53.50
86	Distribution cables (excluding LV)	0.0532	1.40
87	Distribution other (excluding LV)	–	–

88
10(v): Fault Rate

		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
89	**Main equipment involved**			
90	Subtransmission lines	11	382.76	2.87
91	Subtransmission cables	–	8.04	–
92	Subtransmission other	–		
93	Distribution lines (excluding LV)	276	1,920.26	14.37
94	Distribution cables (excluding LV)	4	348.38	1.15
95	Distribution other (excluding LV)	–		
96	**Total**	291		
97				

Company Name	**EA Networks**
For Year Ended	**31 March 2024**
Network / Sub-network Name	**Total Network**

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

8 **10(vi): Worst-performing feeders (unplanned)** *Not required before DY2025*

9

10 **SAIDI**

sch ref	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)
12	1							
13	2							
14	3							
15	4							

16 [1] *Extend table as necessary to disclose all worst-performing feeders*

17

18 **SAIFI**

sch ref	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)
20	1							
21	2							
22	3							
23	4							

24 [1] *Extend table as necessary to disclose all worst-performing feeders*

25

26 **Customer Impact**

sch ref	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)
28	1							
29	2							
30	3							
31	4							

32 [1] *Extend table as necessary to disclose all worst-performing feeders*

Company Name EA Networks

For Year Ended 31 March 2024

Schedule 14 Mandatory Explanatory Notes

(Guidance Note: This Microsoft Word version of Schedules 14, 14a and 15 is from the Electricity Distribution Information Disclosure Determination 2012 (Targeted Review) Amendement Determination 2024 - Clause references in this template are to that determination)

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).

Return on Investment (Schedule 2)

4.1 Comment on return on investment as disclosed in Schedule 2

ROI for FY24 was 5.54% compared to 8.40% the previous year. The decrease was due to reduced:

- Regulatory Profit of $20.5m is $6.8m (24.9%) less than RY23 driven largely due to reduced RAB revaluation ($7.6m) on the back of lower CPI (263bps), increased operational expenditure incl pass through and recoverable costs ($2.5m) and higher depreciation ($0.8m), partially offset by increased regulatory income ($3.8m) and reduced tax allowance ($0.3m).
- A higher Regulatory Asset Base requiring increased profits to maintain the same ROI.
- Cost of debt in RY24 of 5.97% v 4.38% in prior year reducing ROI.

The Commerce Commission set prices assuming that CPI would be 2.00% for the 2023-24 year, which would have resulted in $6.9m revaluation on RAB assets. Actual inflation for the corresponding period was 4.02% (PY: 6.65%), which has resulted in a $13.8m (PY: $21.4m) revaluation of RAB assets.

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

There has been no re-classification of items in the disclosure year in accordance with the requirements of 2.7.1(2).

Regulatory Profit (Schedule 3)

5. In the box below, comment on regulatory profit for the disclosure year as disclosed in Schedule 3. This comment must include-

    5.1 a description of material items included in other regulated income (other than gains / (losses) on asset disposals), as disclosed in 3(i) of Schedule 3.

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

Regulatory Profit (Schedule 3)

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

Other regulated income includes $131k (PY:$150k) of new connection fees. Additional information concerning when new connection fees are charged can be found in EA Networks new connection and extension policy downloadable from: https://www.eanetworks.co.nz/assets/PDFs/Disclosures/Regulatory/Other/e7d903803e/New-Connections-Extensions-PolicyEA-v2.pdf.

The other main component of other regulatory income relates to solar applications ($18k). The maximum amount EA can charge for solar applications is detailed in the ‘Electricity industry participation code 2010 and associated amendments’.

The final components and the reason other regulatory income has resulted in a loss is the reclassified amount as described below.

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

No items have been reclassified in accordance with subclause 2.91.(2).

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

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

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

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

Box 3 Merger and acquisition expenses

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

No items have been reclassified 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.

No merger or acquisition occurred in the reporting period.

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)

Comment on the value of the regulatory asset base (rolled forward) in Schedule 4.
During the disclosure year RAB increased by $16.9m. This increase was due to both assets commissioned ($17.1m) and revaluations ($13.7m) a result of CPI remaining high. The movement partially offset by disposals and depreciation during the year. All assets commissioned, decommissioned and depreciated in the year have followed the requirements of the determination.

Information on reclassified items in accordance with subclause 2.7.1(2)
No items have been reclassified in accordance with subclause 2.7.1(2).

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

8. In the box below, provide descriptions and workings of the 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

8.1 Income not included in regulatory profit / (loss) before tax but taxable
None

8.2 Expenditure or loss in regulatory profit / (loss) before tax but not deductible
Non-Deductible entertainment expenses incurred of $48k.

8.3 Income included in regulatory profit / (loss) before tax but not taxable
None

8.4 Expenditure or loss deductible but not in regulatory profit / (loss) before tax
None

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)

Tax effect of other temporary differences	**($000)**
Repayments of new investment contracts	(263)
Annual leave provision and other employee related cost	(5)
Total	**(268)**

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

Comment on cost allocation as disclosed in Schedule 5d
ABAA (accounting-based allocation approach) has been applied to allocate not directly attributable costs in the disclosure year in accordance with the IM determination.

Proxy cost allocators have been used due to no direct relationship existing between not directly attributable business support operating costs and the way costs are incurred.

Information on reclassified items in accordance with subclause 2.7.1(2)
No items have been reclassified in accordance with subclause 2.7.1(2)

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

Comment on cost allocation as disclosed in Schedule 5e
ABAA (accounting-based allocation approach) has been applied to allocate not directly attributable costs in the disclosure year in accordance with the IM determination.

Proxy cost allocators have been used due to no direct relationship exiting between not directly attributable non-network asset and the way in which the asset is employed by EA Networks.

Information on reclassified items in accordance with subclause 2.7.1(2)
No items have been reclassified in accordance with subclause 2.7.1(2)

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-

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

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

Box 9: Explanation of capital expenditure for the disclosure year

12.1 a description of the materiality threshold applied to identify material projects and programs described in Schedule 6a.
Projects individually reported in the 2023 AMP. The budget section of the 2023 AMP gives additional detail concerning how projects are individually sectioned for separate disclosure in the AMP.

The materiality threshold applied to identify material projects is $0.8m, which is based on the audit materiality level. There are no projects that have exceeded this level of materiality.

12.2 information on reclassified items in accordance with subclause 2.7.1(2).
There has been no re-classification in accordance with subclause 2.7.1(2).

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

17. 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

13.1 Commentary on asset replacement or renewal reported in 6b(i) of Schedule 6b
Asset replacement or renewal relates to work undertaken to maintain RAB assets in functional order. An example of such maintenance include:

- Replacement of a cross arm but not the pole itself.
- Repairs to a substation fence, but not the replacement of the fence.
- Repairs to distribution transformers, switchgear, pillar boxes and ABS but not their replacements.
- The relocation cost of moving a physical transformer from one location on the network to another, but not the cost of installing a transformer pad and plumbing it into the network.
- Network operational expenditure is managed together collectively.

13.2 Information on reclassified items in accordance with subclause 2.7.1(2)
There has been no re-classification 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.

There was no atypical expenditure during the period which exceeded the materiality threshold

Variance between forecast and actual expenditure (Schedule 7)

18. 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

In line with the determination, expenditure types are compared to the AMP forecast. When an actual expenditure for a disclosure heading is greater than 110% of the AMP forecast comment is made.

Expenditure on Assets

Total expenditure on assets was $0.6m or 3.4% below forecast and expenditure on network assets was $0.2m or 1.3% lower than forecast. Non-network assets included key projects which did not proceed and/or were operating costs in nature.

The reduction in network asset expenditure was driven by:

- **Consumer connections -** The target was set using historical information and known demand for consumer connection work in the disclosure year. Actual demand for solar farms, subdivisions, and other consumer connections was close to that predicted with expenditure only $0.24m (4.6%) under forecast.
- **System growth** – There were delays to 22kV conversion, LV network monitoring (PowerPilot), and the 66kV tee connection to Lauriston through additional workload around solar farms.
- **Asset replacement and renewal –** Actual expenditure was $1.96m (25%) above forecast. A lot of the forecast work was completed, but some of the completed works went over forecast. The reasons varied. Some were unanticipated complexities in work execution. There was also a significant amount of unscheduled replacements caused by faults and additional inspection work revealing the need for unplanned renewal. Some work also carried over from the previous year by a few months.
- **Quality of Supply -** Actual spending on quality of supply was 46% lower than the forecast. The underspend is predominantly SCADA engineering resource being diverted to solar farm connection work and the need to gather data on surge arresters before undertaking a replacement programme.
- **Other reliability, safety, and environment –** Actual spending was $45k (11%) below forecast. The largest component of this work is earthing upgrades, and they were more than expected. Other work, particularly seismic upgrades, was delayed.
- **Overhead to underground conversion –** Spend on converting lines from overhead to underground ended $0.8m (26%) over forecast with some spillover from the previous year.

Operational Expenditure

Total operational expenditure was 25% below forecast. Network operational expenditure was 8% lower than target largely driven by:

- **Service interruptions and emergencies –** The target set based on historic level and provision for increased cost of major events, while RY24 saw just two major events leading to lower than anticipated spend thanks to stable weather throughout the year.

  Faults, by their nature are difficult to predict from year to year, with extreme weather being a large contributor along with unplanned events such as vehicles striking poles.

  The number of unplanned interruptions on the network of 282 is down on prior year (302):
    - SAIFI class C (the average number of unplanned supply interruptions per connected consumer) value of 1.16 was 12% lower v 1.32 the previous year.
    - SAIDI class C (the average duration of supply interruptions per connected consumer) value of 59.28 was 49% lower compared to 116.26 for the previous year.

- **Vegetation management -** Whilst an uplift in spend on RY23 levels was forecast, vegetation spend was higher than forecast in RY24 with the move to contracting out vegetation management for scoping and trimming inflating costs v inhouse.
- A vegetation supervisor was appointed during the year also driving costs higher v prior year.
- **Routine and corrective maintenance and inspection -** The higher than planned expenditure reflects a balance of work between capex and maintenance programs. RY24 spend is $105k down on prior year.

System operations and network support – The $4.2m RY24 spend is in line with prior year but short of the $7.8m forecast as several projects were delayed including the IT system implementation

Information relating to revenues and quantities for the disclosure year

19. In the box below provide-

20. 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

    20.1 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

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.

Targeted line charges ($45.9 million) closely matched actual line charge revenue ($47.0 million) or 2%.

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

Increased volume of electricity demanded from customers drove the RY24 forecast uplift.

Network Reliability for the Disclosure Year (Schedule 10)

21. 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.

Interruptions by class *(per Schedule 10(i))*	**RY24**	**RY23**	**% Var.**
Class B (planned interruptions on the network)	294	282	4.3%
Class C (unplanned interruptions on the network)	282	300	-6.0%
Class G (unplanned interruptions caused by another disclosing entity)	3	2	50.0%
Total	**579**	**584**	**-0.9%**

Planned interruptions – The increase in planned interruptions is due to more isolation points available in the areas worked on. This led to more outages, but each outage smaller in terms of duration and customers impacted, as supported by the lower SAIDI (112.01; RY23: 121.45) and SAIFI (0.4052; RY23: 0.4587).

Interruptions restoration - Class C interruptions with a restore time greater than 3 hours decreased to 66 (was 73 in 2023) helping drive SAIDI down to 59.28 (RY23: 116.26).

Overall, Class C interruptions continued to reduce, down by 18 on FY23, reflective of the increased investment into vegetation management reducing the risk of tree impacts during bad weather.

Class C interruptions major contributors

10(ii) SAIDI Class C Interruptions - For the 2024 regulatory year SAIDI caused by vegetation faults reduced on prior year, the increased spend on vegetation management reducing risk of in-zone trees damaging the network.

Defective equipment was not as prevalent in RY24 with SAIDI minutes down 47% on prior year.

10(ii) SAIFI Class C Interruptions – Human error was the largest contributor to SAIFI despite only 4 events due to 'human element' leading to the SAIFI major event. After normalization SAIFI reduced significantly.

Defective Equipment was again a large contributor to the SAIFI figures albeit 43% down on prior year, broken conductor being the most common cause. Corrosion of conductor joins have been causing the failures and are gradually being replaced during restoration or part of line maintenance.

Limitation on reliability information

Even through EA Networks reliability is compliant with ID's quality requirements there are inherent limitations in the ability to collect and record the network reliability information to be disclosed in Schedule 10(1) to 10(iv). Consequently, there is no independent evidence available to support the accuracy of recorded faults, and EA Networks has limited control over the completeness and accuracy of installation control point ('ICP') data included in the SAIDI and SAIFI calculations.

Insurance cover

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

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

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

17.1 level of insurance

Where it is economically sensible to insure assets EA Networks has insurance in place. In practice this means that most items outside of substation fencing will not be insured.

17.2 levels of reserves

EA Networks holds no insurance reserves.

Amendments to previously disclosed information

25. 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:

25.1 a description of each error; and

26. 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 material errors have been identified.

Company Name	EA Networks
For Year Ended	31 March 2024

Schedule 14a Mandatory Explanatory Notes on Forecast Information

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.2.6.

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

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

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

Box 1: Commentary on difference between nominal and constant price capital expenditure forecasts

Consistent with the previous year constant price operating and capital expenditure were inflated to reflect forecast nominal prices.

Costs have been prepared using 2023-24 values for labour, plant, and materials. Years after 2024-25 have been escalated by the “Half Year Economic and Fiscal Update 2022” CPI Forecast by the New Zealand Government Treasury published in December 2022. When the forecast ends, the final year CPI value has been used util the period end.
(**Half Year Economic and Fiscal Update 2022 | The Treasury New Zealand**)

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

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

Box 2: Commentary on difference between nominal and constant price operational expenditure forecasts

Consistent with the previous year constant price operating and capital expenditure were inflated to reflect forecast nominal prices.

Costs have been prepared using 2023-24 values for labour, plant, and materials. Years after 2024-25 have been escalated by the “Half Year Economic and Fiscal Update 2022” CPI Forecast by the New Zealand Government Treasury published in December 2022. When the forecast ends, the final year CPI value has been used util the period end.
(**Half Year Economic and Fiscal Update 2022 | The Treasury New Zealand**)

Company Name EA Networks

For Year Ended 31 March 2024

Schedule 15 Voluntary Explanatory Notes

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024)

This schedule enables EDBs to provide, should they wish to-

5. 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;

6. information on any substantial changes to information disclosed in relation to a prior disclosure year, as a result of final wash-ups.

7. 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.

8. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Schedule 9a and 9b

Continuing improvement in the accuracy of our GIS systems, and an ongoing review and cleanse of data led to corrections in recorded pole population, including identifying streetlight poles and correcting the private ownership status of some poles.

Schedule 5a

Following the legislation change to remove tax depreciation deductions on buildings with original estimated useful lives of 50 years or more, an entry has been made in Schedule 5a(viii) ‘Other adjustment to the RAB tax value’ to remove the existing buildings relating to this change from the Regulatory Tax Asset Base Roll-Forward. This change was required to accurately calculate deferred tax levels. The amount included was $2.5m reducing the Regulatory tax asset base closing value in FY24.

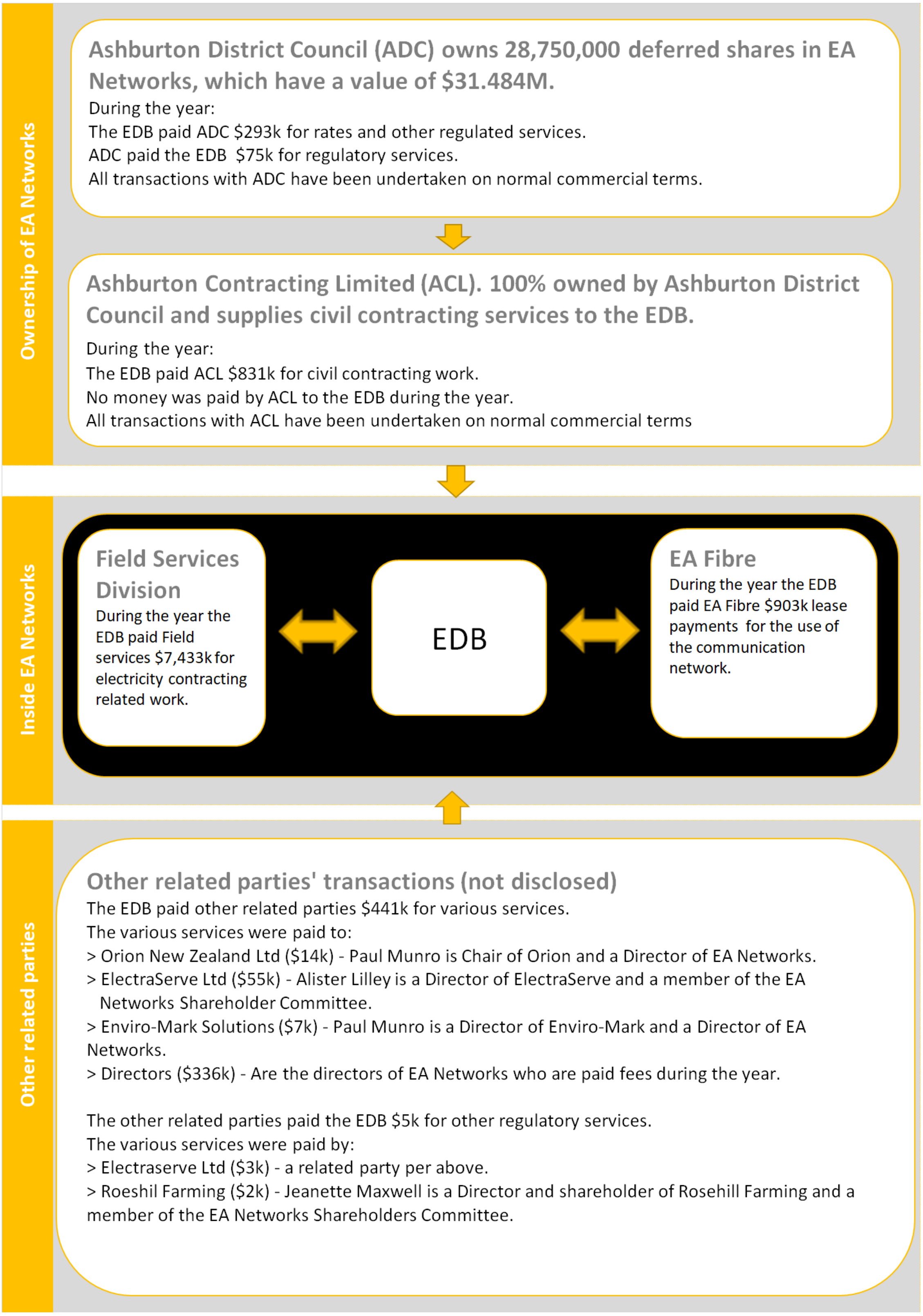
Appendix A:
EA Networks
Related Party requirements of the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024

For the year ended 31 March 2024

Dated 29 August 2024

Requirement 2.3.8 (1) The relationships between the EDB and the related party

This diagram identifies the key related parties Ashburton Contracting Limited, Ashburton District Council, EA Field Services, and EA Fibre.



Ownership of EA Networks

Ashburton District Council (ADC) owns 28,750,000 deferred shares in EA Networks, which have a value of $31.484M.

During the year:
The EDB paid ADC $293k for rates and other regulated services.
ADC paid the EDB $75k for regulatory services.
All transactions with ADC have been undertaken on normal commercial terms.

Ashburton Contracting Limited (ACL). 100% owned by Ashburton District Council and supplies civil contracting services to the EDB.

During the year:
The EDB paid ACL $831k for civil contracting work.
No money was paid by ACL to the EDB during the year.
All transactions with ACL have been undertaken on normal commercial terms

Inside EA Networks

Field Services Division

During the year the EDB paid Field services $7,433k for electricity contracting related work.

EDB

EA Fibre

During the year the EDB paid EA Fibre $903k lease payments for the use of the communication network.

Other related parties

Other related parties' transactions (not disclosed)

The EDB paid other related parties $441k for various services.
The various services were paid to:
> Orion New Zealand Ltd ($14k) - Paul Munro is Chair of Orion and a Director of EA Networks.
> ElectraServe Ltd ($55k) - Alister Lilley is a Director of ElectraServe and a member of the EA Networks Shareholder Committee.
> Enviro-Mark Solutions ($7k) - Paul Munro is a Director of Enviro-Mark and a Director of EA Networks.
> Directors ($336k) - Are the directors of EA Networks who are paid fees during the year.

The other related parties paid the EDB $5k for other regulatory services.
The various services were paid by:
> Electraserve Ltd ($3k) - a related party per above.
> Roeshil Farming ($2k) - Jeanette Maxwell is a Director and shareholder of Rosehill Farming and a member of the EA Networks Shareholders Committee.

Related party: Ashburton District Council

What is the relationship between EA Networks and Ashburton District Council?

Ashburton District Council (ADC) is a significant shareholder that holds 28,750,000 deferred shares and appoints 3 out of 7 members onto EA Networks Shareholders Committee.

The role of the Shareholders Committee and Shareholders Committee ability to control EA Networks

Section 16.22 of Electricity Ashburton Limited, trading as EA Networks, Constitution stops the Shareholders Committee from directing or instructing the Board, or Management, to undertake any actions. The function of the Shareholders Committee shall be:

- To receive reports from the Board of EA Networks so that the Shareholders Committee can report to the shareholders as to whether or not the Board is meeting the reasonable expectations of the shareholders Committee in governing and controlling the Company.
- To appoint the Directors of the Company in accordance with the criteria established by the Shareholders Committee as reviewed and revised from time to time. The criteria established by the Shareholders Committee shall ensure that a balanced Board of Directors comprising people of high business acumen will be appointed as Directors of the Company. The criteria established by the Shareholder Committee will be available to all shareholders of the Company.

Section 19.9 of the Constitution allows each member of the shareholders Committee to have one vote each. In the case of an equality of votes the chairperson shall have a second or casting vote.

ADC Share ownership in EA Networks

ADC owns:

- 100 $1 Rebate shares on the same terms and conditions as all consumers/shareholders who own rebate shares.
- 28,750,000 deferred shares. The deferred shares:
    - hold no voting rights unless EA Networks is subject to sale.
    - have no rights to any distribution unless the company is sold.

What is Ashburton District Council's purpose?

The principal activities of the Ashburton District Council (ADC) are defined in section 10 of the Local Government Act 2002 as

The purpose of local government is –

a. To enable democratic local decision-making and action by, and on behalf of, communities; and
b. To promote social, economic, environmental, and cultural well-being of communities in the present and for the future.

Financial benefits ADC received as an owner of EA Networks

For the disclosure year ADC received no financial benefits due to its ownership interest in EA Networks.

Like all consumers connected to the EDB's network at the qualifying date, ADC received a consumer discount, paid via their electricity retailer. The value of consumer discount was calculated in accordance with EA Networks consumer discount methodology. The consumer discount methodology is downloadable from EA Networks website, www.eanetworks.co.nz.

Requirement 2.3.10: A summary of EA Networks current policy in respect of the procurement of assets or goods or services from any related party.

EA Networks Procurement Policies requires all related parties, excluding EA Fibre and EA Field Services, to tender for work as an independent contractor unrelated to the EDB.

In practice, most services supplied by ADC to EA Networks fall under the Local Government Act 2002. This Act requires the ADC to set uniform annual charges regardless of ownership.

Requirement 2.3.12 (1): A description of how the EDB applies its current policy for the procurement of assets or goods or services from a related party in practice.

The EDB undertakes commercial transactions with ADC using standard terms and conditions.

Requirement 2.3.12 (2): A description of any policies or procedures of the EDB that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party that are related to the supply of the electricity distribution services.

The EDB has no policies or procedures requiring consumers to undertake any purchasing from ADC.

Requirement 2.3.12 (3): Subject to subclause (5), at least one representative example transaction from the disclosure year of how the current policy for the procurement of assets or goods or services from a related party is applied in practice.

The EDB received a rate demand for instalment 2 of 4 in October 2023. The payment:

1. was authorised for payment in accordance with the requirements of the delegated authority policy.
2. paid on the due date (20 November 2023).

The process used:

- to authorise the rate demand for payment.
- to select the actual payment date of the rate demand.

is consistent with all payments made by the EDB.

Requirement 2.3.12 (4): For each representative example transaction specified in accordance with subclause (3), how and when the EDB last tested the arm's-length terms of those transactions.

The Local Body Act 2002 allows councils to strike rates. The Act sets out how rates must be struck and applied to owners of the property in the area serviced by the Local Body. This compliance demonstrates compliance with the arm's-length requirement.

Requirement 2.3.12 (5): Separate representative example transactions where the EDB has applied the current policy for the procurement of assets or goods or services from a related party significantly differently between expenditure categories.

Materially, the Procurement Policy has been applied consistently between expenditure categories.

Related Party: Ashburton Contracting Limited (ACL)

Who is Ashburton Contracting and how is it a related party?

The purpose of ACL

ACL's website states its principal activities include civil services, rural contracting, residential contracting, landscaping supplies, concreting and vehicle workshop services. Additional information on ACL's activities is on their website: https://ashcon.co.nz.

Ability to control

ACL has no ability to appoint members onto the Shareholders Committees or direct management, Board Members, or the Shareholder Committee to undertake any activity solely due to ACL being a subsidiary of ADC.

Mr Andrew Barlass is a Director of Ashburton Contracting Limited and Chair of Electricity Ashburton Limited trading as EA Networks. Mr Barlass' ability to control Ashburton Contracting Limited is limited to that which a Director would normally discharge their responsibilities.

Financial return to ACL from the EDB

For the disclosure year, ACL has no ownership interest in EA Networks.

Like all consumers connected to the EDB's network at the qualifying date, ACL received a consumer discount, paid via their electricity retailer. The value of consumer discount was calculated in accordance with EA Networks consumer discount methodology. The consumer discount methodology is downloadable from EA Networks website, www.eanetworks.co.nz.

Requirement 2.3.10: A summary of EA Networks current policy in respect of the procurement of assets or goods or services from any related party.

ACL supplies fill for trenching and civil contracting services to Field Services and the EDB.

The minor works section of the procurement policy requires that "for construction and maintenance work under $200k, associated with electricity and fibre distribution assets a minor tender rate card will be used. One or more contractors may appear on the minor tender rate card, which will be re-tendered every 18 months. Awarding of the minor works contractors will be determined on price, ability to meet forecasted requirements, and work history of the contractor".

The major works section of the procurement policy required that "for electricity contracting and maintenance work over $200k, the work will be tendered out. Evaluation of tenders will be based on the attributes set out in the tender documents, taking into consideration the Health and Safety track record of tenders and ability of the contractor to perform the required work within the stipulated timeframe".

Requirement 2.3.12 (1): A description of how the EDB applies its current policy for the procurement of assets or goods or services from a related party in practice.

The EDB uses normal commercial terms when transacting with ACL. No benefits are given to either party due to the ownership structure.

Requirement 2.3.12 (2): A description of any policies or procedures of the EDB that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party that are related to the supply of the electricity distribution services.

The EDB has no policies or procedures requiring a consumer to purchase assets, goods, and/or services from ACL.

Requirement 2.3.12 (3): Subject to subclause (5), at least one representative example transaction from the disclosure year of how the current policy for the procurement of assets or goods or services from a related party is applied in practice.

On 31 October 2023, the first progress claim was received related to the Tancred St project (Job # 692180) for trenching and related works. An assessment using the fixed rate cards valid to end of May 2024 had the project within the Minor works procurement level of the policy. There were two contractors approved to perform the work scoped, ACL the only contractor available to deliver within the required timeframe thus winning the work.

Requirement 2.3.12 (4): For each representative example transaction specified in accordance with subclause (3), how and when the EDB last tested the arm's-length terms of those transactions.

EA Networks procured the services of ACL through the procurement process described below (Requirement 2.3.12(5)). The degree of work is covered within the existing 'major works' contract of both approved civil contractors. ACL was awarded the contract based on capacity to carry out the work within required timeframes.

Requirement 2.3.12 (5): Separate representative example transactions where the EDB has applied the current policy for the procurement of assets or goods or services from a related party significantly differently between expenditure categories.

Purchase of topsoil only with invoice #466648 less than $5k. Simple market analysis applies per the procurement policy. ACL product was known and available therefore procured. No purchase order required, and invoice paid on due date of 20th of the following month.

Related party: EA Fibre

Due to its coverage EA Fibre is the preferred supplier of high-speed communications to the EDB. As EA Fibre is required to stand on its own feet, the EDB is charged for its services at a commercial rate. Currently there are no other high-speed communication networks which can supply the same level of services as EA Fibre supplies the EDB.

Requirement 2.3.10: A summary of EA Networks current policy in respect of the procurement of assets or goods or services from any related party.

EA Networks procurement policy allows high speed communication services to be purchased from anyone able to supply the required service. Currently there is only one supplier of rural fibre services within the EDB network area. The supplier is EA Fibre.

Requirement 2.3.12 (1): A description of how the EDB applies its current policy for the procurement of assets or goods or services from a related party in practice.

At the time of installing the fibre network, and still the case, EA Fibre is the only supplier able to supply the required service. This means that EA Fibre is the agreed supplier for the high-speed communication network. Consistent with ‘large users’ of the fibre network the EDB has been charged a daily fee. The fee charged has been calculated using the same principles as another large user on the network.

Requirement 2.3.12 (2): A description of any policies or procedures of the EDB that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party that are related to the supply of the electricity distribution services.

The EDB has no policies or procedures requiring a consumer to purchase assets or goods or services from EA Fibre.

Requirement 2.3.12 (3): Subject to subclause (5), at least one representative example transaction from the disclosure year of how the current policy for the procurement of assets or goods or services from a related party is applied in practice.

The EDB has a long-term financial lease with the fibre business. The present value of the financial lease was recorded in the RAB when the EDB adopted NZ IFRS 16, Leases. The EDB was required to pay an annual fee of $903k to EA Fibre during the year.

Requirement 2.3.12 (4): For each representative example transaction specified in accordance with subclause (3), how and when the EDB last tested the arm's-length terms of those transactions.

There is no other rural supplier of a high-speed fibre networks servicing the Ashburton District to test EDB fibre charges against. As a proxy for realistic commercial return, we examined how another large consumer on the fibre Network's charge was determined and applied the same pricing principles against the EDB charge. The calculation of the EDB and other large users' charges are consistent.

Requirement 2.3.12 (5): Separate representative example transactions where the EDB has applied the current policy for the procurement of assets or goods or services from a related party significantly differently between expenditure categories.

There were no significant differences between expenditure categories.

Related party: Field Services

In formulating our procurement policy, we have considered our geographical location, supply standard required by our consumers and access to critical services during a network emergency. Having considered these key elements we have formed the view that an inhouse contracting service (Field Services) best meet the needs of our consumers/shareholders. Field Services has been sized to meet the daily and emergency requirements of the network, in a cost-effective manner. To this end work undertaken by Field Services is at cost.

Field Services supplies underground, overhead and technical services to the EDB

- The underground department installs and maintains electricity distribution network assets located underground.
- The overhead department installs and maintains electricity distribution network assets located above ground.
- Technical services undertake work associated with zone substations, protection, and transformers.

Requirement 2.3.10: A summary of EA Networks current policy in respect of the procurement of assets or goods or services from any related party.

Our procurement policy requires that electricity network construction and maintenance work is to be undertaken by Field Services. If Field Services are unable to complete the work in question it is tendered out.

Work tendered out falls into one of two categories:

Minor works contract

For construction and maintenance work under $200k, associated with electricity and fibre distribution assets a minor tender rate card will be used. One or more contractors may appear on the minor tender rate card, which will be re-tendered every 18 months. Awarding of minor works to a contractor will be determined on price, ability to meet forecast requirements, and work history of the contractor.

Non-minor works contract

For electricity contracting and maintenance work over $200k, the work will be tendered out. Evaluation of tenders will be based on the attributes set out in the tender documents, taking into consideration the Health and Safety track record of tenders and ability of the contractor to perform the required work within the stipulated timeframe.

Requirement 2.3.12 (1): A description of how the EDB applies its current policy for the procurement of assets or goods or services from a related party in practice.

All contracting work that Field Services can perform is discussed between Field Services and the EDB to identify the resources required to undertake the work. Where Field Services lack the required resources, the work is awarded under the minor works contract or tendered out.

Requirement 2.3.12 (2). A description of any policies or procedures of the EDB that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party that are related to the supply of the electricity distribution services.

EA Networks has no policies requiring a consumer to purchase services from a related party.

Our capital contribution policy requires consumers to contribute to assets which EA Networks own. The customer is free to choose who undertakes any work on their property, provided that the person/entity undertaking the work is qualified to do so.

Consumers required to undertake tree work to protect the network, are free to choose from an approved contractor list.

Our notices to consumers notifying them of work required on their privately-owned networks, state that they are free to choose who undertakes the work.

Requirement 2.3.12 (3) subject to subclause (5), at least one representative example transaction from the disclosure year of how the current policy for the procurement of assets or goods or services from a related party is applied in practice.

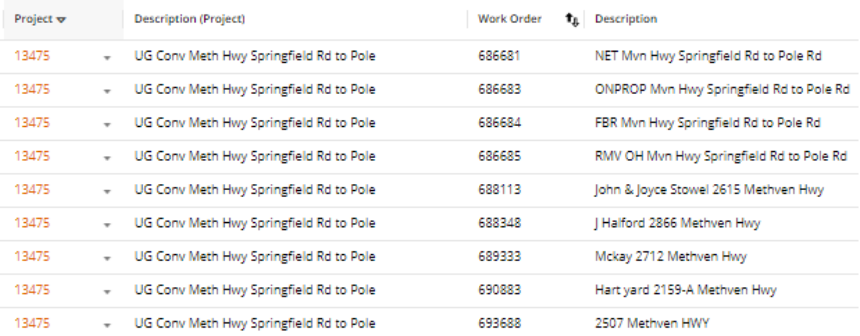
A project to convert overhead line to underground that required tendering out.

Field Services – Project requiring a sub-contactor

Project 13475 : UG Conv Meth Hwy Springfield Rd to Pole

This project was designed and scoped by the EDB.

1. The assets team created work orders on behalf of the underground team instructing Field Services to undertake the required scope of work, as shown below.



Project	Description (Project)	Work Order	Description
13475	UG Conv Meth Hwy Springfield Rd to Pole	686681	NET Mvn Hwy Springfield Rd to Pole Rd
13475	UG Conv Meth Hwy Springfield Rd to Pole	686683	ONPROP Mvn Hwy Springfield Rd to Pole Rd
13475	UG Conv Meth Hwy Springfield Rd to Pole	686684	FBR Mvn Hwy Springfield Rd to Pole Rd
13475	UG Conv Meth Hwy Springfield Rd to Pole	686685	RMV OH Mvn Hwy Springfield Rd to Pole Rd
13475	UG Conv Meth Hwy Springfield Rd to Pole	688113	John & Joyce Stowel 2615 Methven Hwy
13475	UG Conv Meth Hwy Springfield Rd to Pole	688348	J Halford 2866 Methven Hwy
13475	UG Conv Meth Hwy Springfield Rd to Pole	689333	Mckay 2712 Methven Hwy
13475	UG Conv Meth Hwy Springfield Rd to Pole	690883	Hart yard 2159-A Methven Hwy
13475	UG Conv Meth Hwy Springfield Rd to Pole	693688	2507 Methven HWY

2. Field services received the project from the EDB. Field Services General Manager and the Field Services Underground Manager identified that the project required a level of drilling which was outside their abilities.
3. Management of Field Services estimated that the required drilling was above the maximum value allowed under minor contracts and tendered the work using NZS 3910 as the basis.
4. EA Networks has followed the procurement policy by tendering out the work. The civil construction part of the contract was awarded under the non-minor works process.
5. Field Services undertook the balance of the required work, which was to install and commission the cable as well as decommission existing overhead lines and poles. Labour and plant costs associated with the project was booked to each task as they were incurred. Stock used by Field Services was booked out of the network store and onto the job as required.
6. At the end of each milestone the successful tender send EA Networks claims for work completed. For example: Claim Number 1, which was sent to EA Field Services on 29 September 2023 and paid on 19 October 2023 under the terms of the contract.
7. At the completion of the project, the transactions associated with the project were sent to the Underground Manager who reviewed them and approved the cost of the project.

Requirement 2.3.12 (4) for each representative example transaction specified in accordance with subclause (3), how and when the EDB last tested the arm's-length terms of those transactions.

Work undertaken by Field Services for the EDB is carried out at cost, with no internal profit being created.

<u>How and when we have tested the arm's length terms:</u>

Our budgeting process sets a rate card for Field Services work, which recovers their operating costs only. At the end of the year, we reviewed internal work carried out by Field Services and determined that no profit was created from work undertaken for the EDB. During the year-end financial audit our auditors reviewed our internal profit calculation and confirmed that no material internal profit was created from internal transactions associated with Field Services.

The rate charged by Field Services for external work is calculated as the internal charge out rate + required markup rate for the job in question. This demonstrates that work charged to external parties incurs the same costs as work carried out for the EDB by Field Services.

In 2023 we tested the charge out rates of Field Services against other contractors which we had engaged. The results found that Field Services charge out rates were lower than the independent contractor.

As our testing of Field Services charge out rates with another contractor demonstrates, the price which Field Services charges the EDB is fair and reasonable.

Requirement 2.3.12 (5) separate representative example transactions where the EDB has applied the current policy for the procurement of assets or goods or services from a related party significantly differently between expenditure categories.

There were no significant differences between expenditure categories.

Related Party: Other Related Parties

Who is included in Other Related Parties and how is each a related party?

The purpose of Other Related Parties

Other related parties included where further information can be found on their website are:

- Orion is an EDB (https://www.oriongroup.co.nz)
- ElectraServe (https://electraserve.co.nz)
- Enviro-Mark Solutions (https://www.toitu.co.nz/)
- Directors

Ability to control

The related parties above have no ability to control EA Networks.

Paul Munro is a director of Orion New Zealand Limited and Enviro-Mark Solutions and has been a director of Electricity Ashburton Limited trading as EA Networks for the full year. Mr Munro's ability to control Orion New Zealand Limited and/or Enviro-Mark Solutions is limited to that which a director would normally discharge their responsibilities.

Alister Lilley is a director of ElectraServe Limited and is a member of the EA Networks Shareholder Committee. Mr Lilley's ability to control ElectraServe Limited is limited to that which a director would normally discharge their responsibilities.

Directors Richard Fitzgerald, Janine Holland, Andrew Barlass, Cole Groves, Rob Jamieson, Paul Munro, Tony Gray were directors of EA Networks for all or part of the year.

Financial return to Other Related Parties from the EDB

For the disclosure year, Orion, ElectraServe, Enviro-Mark solutions and Directors received no financial benefits due to being a related party.

Requirement 2.3.10: A summary of EA Networks current policy in respect of the procurement of assets or goods or services from any related party.

Orion supplies load management services for all EDB's in the upper South Island. The cost associated with running the load management services is shared among the EDB's that use the service. We also paid Orion for their supply to our upper Rakaia embedded network.

ElectraServe won the tender process for the solar panel installation on the EA Networks building after receiving two quotes, being the two local companies deemed to be adequately resourced to carry out the work. ElectraServe also provided emergency work relating to lighting repairs to the EA Networks building therefore foregoing routine procurement procedures as per the procurement policy. ElectraServe paid EA networks for connection fees and capital contributions during the year.

Enviro-Mark Solutions charged an annual license fee for software services provided to EA Networks.

The EDB and Orion, ElectraServe, Enviro-Mark Solutions and the Directors receive no benefits when transacting with each other, due to the related party relationship.

The Directors formed the board of directors for EA Networks and provided services as would usually be expected in exchange for a predetermined annual fee.

Requirement 2.3.12 (1): A description of how the EDB applies its current policy for the procurement of assets or goods or services from a related party in practice.

The EDB uses normal commercial terms when transacting with Orion, ElectraServe Limited, Enviro-Mark Solutions and the Directors. No benefits are given to either party due to the ownership structure.

Requirement 2.3.12 (2): A description of any policies or procedures of the EDB that require or have the effect of requiring a consumer to purchase assets or goods or services from a related party that are related to the supply of the electricity distribution services.

The EDB has no policies or procedures requiring a consumer to purchase assets, goods, and/or services from Orion, ElectraServe Limited, Enviro-Mark Solutions and the Directors.

Requirement 2.3.12 (3): Subject to subclause (5), at least one representative example transaction from the disclosure year of how the current policy for the procurement of assets or goods or services from a related party is applied in practice.

EA Networks received an invoice in May 2023 (SINV34548) relating to USI load management services for the year to 31 March 2024. This invoice was authorised for payment in accordance with the delegated authority policy and coded to operating costs. The invoice was paid on 20 June 2023.

Requirement 2.3.12 (4): For each representative example transaction specified in accordance with subclause (3), how and when the EDB last tested the arm's-length terms of those transactions.

The service supplied by Orion is not offered by any-other service provider. As a result, we are unable to carry out market testing. EA Networks has a contract in place with Orion, governing the calculation of charges, this contract was put in place before Orion became a related party.

Requirement 2.3.12 (5): Separate representative example transactions where the EDB has applied the current policy for the procurement of assets or goods or services from a related party significantly differently between expenditure categories.

The Services provided by Orion are outside of the scope of the procurement policy.

Schedule 18 **Certification for Year-end Disclosures**

Clause 2.9.2 and 2.9.5

We, Andrew David Barlass, and Paul Jason Munro being directors of Electricity Ashburton t/a EA Networks 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, 2.3.8-2.3.12, 2.4.21, 2.4.22, 2.5.1(1)(a)-(f), 2.5.2, 2.5.2A, 2.6.1B 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, 10a and 14 has been properly extracted from the EA Networks 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.

Andrew David Barlass
29 August 2024

Paul Jason Munro
29 August 2024

Map of Anticipated Network Expenditure and Network Constraints

As required by sections 2.3.13 - 2.3.16 the following text details the projects/programmes that represent the largest forecast operational and capital expenditure and the network/equipment constraints that could be addressed by the projects/programmes.

The map is intended to be used in digital form and contains layers that relate to some of the items detailed below. In paper printed form, the map will be very difficult to interpret.

10 Largest (by Value) Operational Projects/Programmes

ID	Name	Description	Timing	Average Value ($)	Location
(OB) * 12024	**Inspecting, Organising and Trimming Trees**	The inspection of trees, the liaison with tree owners and the subsequent trimming or felling of trees which are considered be a risk to the electricity network.	2025-2034	1 045k p.a.	All Line Locations (Map inset)
(OA) 12003	**Overhead Repairs to Restore Power**	The immediate work required after a fault has occurred on all voltages of the overhead network to restore supply to all affected consumers.	2025-2034	756k p.a.	All OH Line Locations (Map inset)
(OF) 12002	**Overhead Planned Repairs & Maintenance**	Scheduled maintenance of overhead line assets of all voltages. Generally, a consequence of inspections revealing an issue more widespread than a single structure. Work is normally planned the prior year.	2025-2034	644k p.a.	All OH Line Locations (Map inset)
(OC) 11998	**ZSS Asset Inspection, Testing & Minor Maintenance**	The inspection of zone substation assets, routine testing of those assets, and minor maintenance that arises as an immediate result of those inspections and tests.	2025-2034	609k p.a.	***Zone Substations*** Layer
(OH) 12017	**DSS, DTX, & D Switchgear Inspection, Testing, & Minor Maintenance**	The inspection of distribution substation and distribution transformer assets, routine testing of those assets, and minor maintenance that arises because of those inspections and tests.	2025-2034	558k p.a.	Substations & Workshop
(OE) 12018	**DSS, DTX, & D Switchgear Planned Maintenance**	The planned maintenance of all types of distribution substations, distribution transformers, and distribution switchgear. Includes ring main units, pole-mounted switches and circuit-breakers, kiosks, and LV switchgear within the kiosks.	2025-2034	243k p.a.	All Distribution Substation Locations and ***EA***

					Networks HQ Layer
(OJ) 12015	**ZSS Asset Planned Repairs & Maintenance**	Scheduled maintenance of assets within the zone substations. Generally, a consequence of inspections revealing an issue that is not readily resolved during the inspection process and requires additional parts or resources to complete.	2025-2034	220k p.a.	*Zone Substations* Layer
(OK) 12002	**22/11kV/LV OH Removal Associated with OH Rebuilds**	The work to remove an end-of-life overhead line during/after the construction work for a new replacement line.	2025-2034	187k p.a.	All OH Line Locations (Map inset)
(OL) 12017	**22/11kV/LV OH Removal Following UG Conversion**	The work to remove an end-of-life overhead line after the construction of an underground network replacing the old overhead line.	2025-2034	132k p.a.	*Urban UG Conversion* Layer and Methven Hwy OH Layer
(OD) 12001	**Overhead Inspection, Testing and Minor Maintenance**	The inspection, testing and minor maintenance of overhead line assets of all voltages.	2025-2034	121k p.a.	All OH Line Locations (Map inset)

Few of the items described above have specific locations that can be readily mapped. Zone substations (**OC** - 11998, **OJ** - 12015) are shown explicitly on the map and are on their own layer (as are the zone substation names).

Note that the Average Value detailed in the table is an annual average value for the years that expenditure occurs and not an average value over the entire duration of the project or programme.

The operational expenditure projects/programmes identified above:

Status	Situation
Are not	already subject to a contract.
	***** OB (tree work) is currently contracted with an unrelated party via a competitively tendered three-year contract.
Are	forecast to require the supply of assets or goods or services by a related party.
Are	currently indicated for supply by a related party.

10 Largest (by Value) Capital Projects/Programmes

ID	Name	Description	Timing	Average Value ($)	Location
(A) 11136, 11058, 11172	**Consumer Connection**	The addition or modification of assets of all voltages that relate to connecting new or increased loads to the electricity network. This can be the addition of a fuse to a pillar box or the construction of significant 11 kV or 22 kV assets to service a large industrial load or subdivision. These loads appear without advance notice on most occasions.	2025-2034	3 998k p.a.	All Locations
(E) Various	**Overhead Line Rebuild**	Known, condition-based overhead line rebuilds of all voltages are included in this category. There is a pool of lines that are becoming candidates for rebuilding (post 2025) but they are yet to be scheduled and therefore not in this category (they are in the D category above).	2025-2034	1 852k p.a.	Rural Line Locations (Map inset)
(D) 11704, 11079, 11078, 11059	**Unscheduled Projects**	This programme of work is to accommodate the unexpected or unscheduled projects that occur when additional information about condition or constraints becomes known. The largest component of this value is the overhead line rebuilds beyond 2025. The likely rebuild candidates have been grouped but not scheduled at this stage.	2025-2034	1 700k p.a.	Predominantly Rural
(J) Various	**Rural Underground Conversion**	The State Highway network in Mid-Canterbury are high traffic volume routes that have historically had a high number of serious crashes on them. A number of these crashes have involved roadside poles and some of these have been fatal. In conjunction with the NZTA, EA Networks have been replacing end-of-life overhead distribution lines with underground cable on these routes. Some of the remote overhead lines in the foothills of the Southern Alps are at end of life. The most cost-effective way to replace the lines is with underground cable using mole-plough techniques. The projects included in this programme are Ashburton- Methven Highway, Double Hill Run Rd, and Hakatere- Heron Rd.	2025-2027	1 630k p.a.	Rural Underground Conversion Layer
(C) 700, 701	**Decarbonisation & Smart Technologies**	Decarbonisation will require additional capacity in various places, but few industries have committed to it. The need to gather additional information on the electrical network and then provide assets that can react to compensate	2025-2034	1 517k p.a.	All Locations

		for rapid changes in load or power flow direction are covered by this programme. The initial phases allow for LV feeder-level metering, communication, and possibly control. This will permit the network to dynamically interact with loads and generators to ensure a stable supply to all consumers. Additional assets, such as control software, batteries, and dynamic VAr compensation are allowed for in later phases of the programme.			
(B) Various	Urban Underground Conversion	As overhead lines in urban areas reach the end of their useful life, the network is replaced with underground cabling and ground-mounted substations. Multiple projects per year are completed and, on average, sum to the amount identified. This programme of work in Ashburton, Rakaia, Hakatere Huts and Rakaia Huts is due for completion in 2032.	2025-2032	1 448k p.a.	Urban UG Conversion Layer
(F) Various	Distribution Transformers	New distribution transformers are required for new or increased load and conversion from 11 kV to 22 kV. The 11 kV to 22 kV conversion work forms a significant proportion of this value and after 2030 will decline significantly.	2025-2034	904k p.a.	All Locations, but focused on 11-22 kV Conversion Layer
(H) 12470, & Others	Ashburton 11kV Core Network	This programme is for additional reliability, resilience, capacity, and security within the Ashburton township urban area. It consists of a series of high capacity 11 kV circuits interconnecting zone substations with network centres (circuit-breaker switchboards) which have multiple smaller feeders radiating from them. The goal is to reduce ICP count per feeder circuit-breaker to less than 250 while increasing network resilience to multiple failures.	2025-2031	631k p.a.	Ashburton Township - *Core Network* Layers
(I) Various	11 kV to 22 kV Conversion	Progressive conversion of rural 11 kV lines to 22 kV. Permits interconnection with surrounding 22 kV network and allows much greater capacity for load and back-feeding during outages. Once of the projects will allow a small zone substation to be decommissioned.	2025-2030	614k p.a.	Predominantly *EA Networks HQ* Layer
(G) Various	Subtransmission Lines	This programme includes new 66kV subtransmission lines being necessary if additional load appears near Fairton.	2025-2029	596k p.a.	Subtransmission Layer

Not all programmes have specific physical locations that can be readily shown on a map. Those programmes that can be located have been allocated a layer in the pdf document and this can be turned on and off to highlight the location(s) involved.

The capital expenditure projects/programmes identified above:

Status	Situation
Are not	already subject to a contract.
Are	forecast to require the supply of assets or goods or services by a related party.
Are	currently indicated for supply by a related party.

Network or Equipment Constraints Involving Large Operational and/or Capital Projects/Programmes

ID	Name	Description	Project Response	Location
1	Inter-Zone Substation Load Transfer	When operating the distribution network at 11 kV, the ability to transfer load between zone substations (such as during a feeder fault near the start of a feeder) is limited by voltage drop in rural areas and cable capacity in urban areas.	(H), (E), (I) & Others (some not listed above)	*11-22kV Conversion* Layer and *Core Network* Layers
2	Zone Substation Transformer Failure	The failure of a zone substation transformer will either interrupt supply or limit capacity to n-1 levels. Both situations require additional capacity from adjacent zone substations to supply the load that cannot be served from the zone substation with the failed transformer. The availability of an urban Ashburton core 11 kV network and a 22 kV rural network provide this facility while a spare transformer is installed. Some general zone substation work also provides more transformation capacity e.g. a solar farm.	(H), (E), (I) & Others (some not listed above)	*11-22kV Conversion* Layer, *Core Network* Layers, *and Zone Substations* Layer.
3	Sub-transmission Circuit Failure	Loss of a single 66 kV circuit will generally not result in loss of supply. It can however cause lower than ideal sub-transmission voltages, and the ability to transfer load at 22 kV or 11 kV is beneficial. Loss of more than one 66 kV circuit (or a single radial 33 kV or 66 kV circuit) will potentially cause loss of supply. These scenarios can be mitigated with additional inter-zone substation transfer capacity or additional subtransmission circuits.	(G), (H), (I) & Others (some not listed above)	*11-22kV Conversion* Layer Subtransmission Layer and *Core Network* Layers

4	Civil Infrastructure Support Failure	During seismic and flooding events, the failure of civil infrastructure such as bridges and roads can cause failure of portions of the electrical network. Additional electrical network paths and capacity can help mitigate this to some degree. Well maintained or new assets also resist these forces better than older assets.	(H), (E), (I) & Others (some not listed above)	*11-22kV Conversion* Layer and *Core Network* Layers. Much of the rural area.
5	Urban 11kV Capacity	The interconnected radial design of the existing Ashburton 11 kV underground network is essentially a traditional overhead line configuration that has served well for several decades. The loading of a number of these circuits is close to reaching full capacity and, during faults, back-feeding can cause slight overload situations. The addition of a layer of larger 11 kV cables that connect to network switching centres and interconnection to the rural 22 kV network during 11 kV cable faults provides both steady state and contingency capacity to alleviate these limitations.	(B), (H), (I) & Others (some not listed above)	*Urban UG Conversion* Layer, *11-22kV Conversion* Layer and *Core Network* Layers.
6	Urban 11kV ICP Count/Feeder	The number of connections per urban 11 kV feeder exceeds the limit set in the EA Networks security standard (some by a large amount). To reduce this to the required level, additional feeders are needed so that for a single cable fault only a limited number of consumers experience the outage. Adding additional feeders to the zone substations would require excessive amounts of cabling to reach the ICPs as well as extensive zone substation rework. The alternative of large core network 11 kV cables connected in closed rings via network centres (new switchboards with additional feeders within the urban network) is a high benefit/value practical solution and advantageous for other constraints as well.	(B) & (H)	*Urban UG Conversion* Layer and *Core Network* Layers.
7	GXP Firm Capacity Exceeded	If a time arises that demand on the Ashburton 220/66 kV grid exit point exceeds the 220 MVA firm capacity for an unacceptable length of time each year, then an additional GXP may be required. At this point in time, it seems to be less likely this will occur within the 10-year AMP planning period. A second GXP comes with overall capacity benefits but does provide several technical and operational disadvantages that are not apparent with one GXP. An alternative is to add more capacity at the existing GXP, but limited egress for 66 kV circuits from the GXP would be the ultimate capacity constraint.	(G) & (I)	Predominantly Located in Rural Areas. Network-wide impacts.
8	Low Voltage Network Capacity	The addition of new or increased load or generation will cause the capacity of LV (low voltage) networks to be tested and in some cases exceeded. The location and	(A), (B), (C), (D), & (F)	Urban Areas.

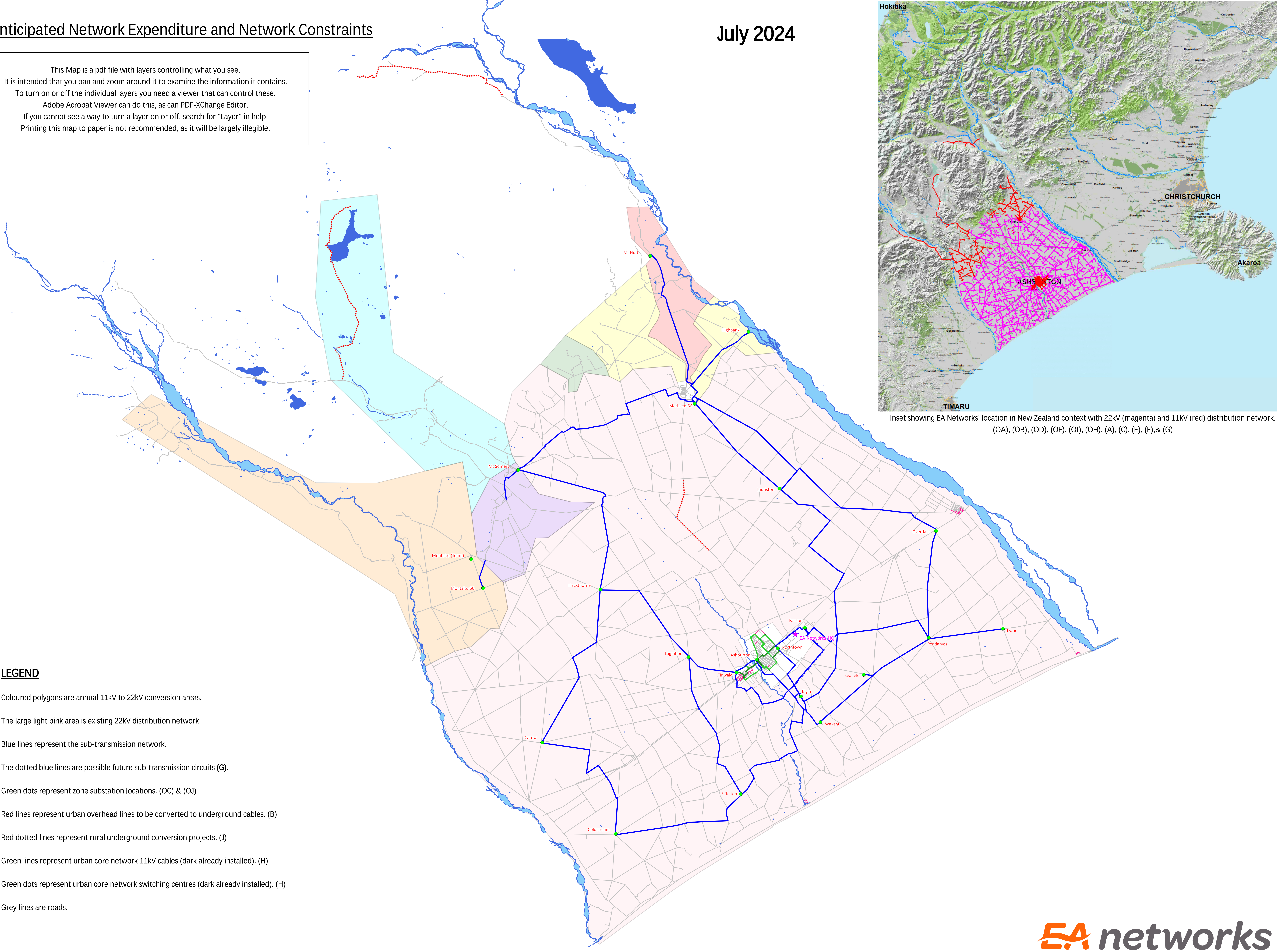
		timing of this new load on existing cables is unknown. To remedy this, additional LV cables and/or distribution substations will be required. Careful load management using demand management control devices will be able to assist in shifting some of the peak demand but, at some stage, additional network assets will still be required.		
9	**Asset Condition - Potential Failure**	All assets deteriorate over time, and it is critical to proactively manage the asset's condition to ensure it does not fail unexpectedly or catastrophically before it is removed from service at end-of-life. Prudent maintenance strategies ensure that inspections, testing, and either refurbishment or replacement occur in a timely and safe manner. All the operational expenditure programmes/projects identified above are in some way contributing to the safe and reliable operation of the electricity network – ensuring any failures that do occur are largely unforeseeable or uneconomical to completely mitigate against.	(OA)-(OJ), (B), (D), (E), (H), (I), & (J)	All Locations - Network-wide.
10	**Network Resilience**	In order to maintain and increase network resilience, there must be both effective maintenance of existing assets to prevent failure in adverse conditions (such as the alpine fault rupturing) and improved/additional assets to assist in recovery from adverse events. All of the projects/programmes identified above contribute in large and small ways to increasing the resilience of the EA Networks electricity network. This ranges from more modern design standards for replacement poles to additional alternative network paths should the primary one be unavailable.	(OA)-(OJ) & (A)-(J)	All Locations - Network-wide.
11	**Generation Constraint**	At Lauriston zone substation, a large (50 MVA) solar generation station is being built. The enlarged substation will be at export capacity during summer when irrigation load is low.	(A)	Zone Substations Layer - Lauriston zone substation.

The constraints detailed above are either explicitly identified in the asset management plan or are alluded to in network development project/programme justifications.

Map of Anticipated Network Expenditure and Network Constraints

July 2024

This Map is a pdf file with layers controlling what you see.
It is intended that you pan and zoom around it to examine the information it contains.
To turn on or off the individual layers you need a viewer that can control these.
Adobe Acrobat Viewer can do this, as can PDF-XChange Editor.
If you cannot see a way to turn a layer on or off, search for "Layer" in help.
Printing this map to paper is not recommended, as it will be largely illegible.



Inset showing EA Networks' location in New Zealand context with 22kV (magenta) and 11kV (red) distribution network.
(OA), (OB), (OD), (OF), (OI), (OH), (A), (C), (E), (F),& (G)

LEGEND

▨ Coloured polygons are annual 11kV to 22kV conversion areas.

▨ The large light pink area is existing 22kV distribution network.

— Blue lines represent the sub-transmission network.

┈ The dotted blue lines are possible future sub-transmission circuits **(G)**.

● Green dots represent zone substation locations. (OC) & (OJ)

— Red lines represent urban overhead lines to be converted to underground cables. (B)

┈ Red dotted lines represent rural underground conversion projects. (J)

— Green lines represent urban core network 11kV cables (dark already installed). (H)

· Green dots represent urban core network switching centres (dark already installed). (H)

— Grey lines are roads.

EA networks
connecting our community

Independent Assurance Report

To the Directors of Electricity Ashburton Limited and the Commerce Commission

Assurance report pursuant to the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2

We have undertaken a reasonable assurance engagement in respect of the compliance of Electricity Ashburton Limited (the "Company") with the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2, (the "Determination") for the disclosure year ended 31 March 2024 where we are required to opine on:

- whether the Company has complied, in all material respects, with the Determination, in preparing the information disclosed under schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10 (limited to SAIDI and SAIFI information), the related party transactions disclosed in Appendix A, and the explanatory notes disclosed in boxes 1 to 11 in Schedule 14 (the 'Disclosure Information'); and
- whether the Company's basis for valuation of related party transactions ('valuation of related party transactions'), 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 Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 23 April 2024) ("the IM Determination").

Qualified Opinion

In our opinion, except for the possible effect of the matter described in the Basis for Qualified Opinion section of our report, in all material respects;

- as far as appears from an examination of them, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the Company;
- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the Company's accounting and other records and has been sourced, where appropriate, from the Company's financial and non-financial systems;
- the Disclosure Information complies with the Determination; and
- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

Basis for Qualified Opinion

As described in Box 13 of Schedule 14, there are inherent limitations in the ability of the Company to collect and record the network reliability information, specifically the installation control points ('ICP's') affected by an interruption and the duration of the interruption used in calculating the amounts required to be disclosed in schedules 10(i) to 10(iv). Consequently, there is no independent evidence available to support the accuracy of the ICP's affected and the duration of an interruption. Controls over the accuracy of ICP and interruption data included in the SAIDI and SAIFI outage statistics are limited throughout the year.

There are no practical audit procedures that we could adopt to independently confirm the accuracy of the ICP data used to record the number of ICP's affected and duration of the interruption for the purposes of inclusion in the amounts relating to SAIDI and SAIFI outage statistics set out in Schedules 10(i) to 10(iv).

Because of the potential effect of the limitations described above, we are unable to form an opinion as to the accuracy and completeness of the data that forms the basis of the compilation of Schedules 10(i) to 10(iv). In this respect alone we have not obtained all the recorded evidence and explanations that we have required.

We have 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 (NZ) 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 Informatio*n.

We believe the evidence we have obtained is sufficient and appropriate to provide a basis for our qualified opinion.

Our assurance approach

Overview

Our assurance engagement is designed to obtain reasonable assurance about the Company's compliance, in all material respects, with the Determination and IM Determination.

Quantitative materiality levels are determined for testing purposes within individual schedules included in the Disclosure Information based on the nature of the information set out in the schedules. These thresholds are determined based on our assessment of errors that could have a material impact on key measures within the Disclosure Information:

- Financial information – any impact resulting in +/-100 basis points of the Return of Investment ('ROI')
- Performance based schedules – 5% of non-financial measures
- Related party transactions – 2% of total related party transactions.

When assessing overall material compliance with the Determination, qualitative factors are considered such as the combined impact on ROI and other key measures as well as assessing the arm's length valuation rules on related party transactions, which may impact on users assessment on whether the purpose of Part 4 of the Commerce Act 1986 has been met.

We have determined that there are three key assurance matters:

- Regulatory Asset Base
- Cost and Asset Allocation
- Related Party Transactions.

Materiality

The scope of our assurance engagement was influenced by our application of materiality.

Based on our professional judgement, we determined certain quantitative thresholds for materiality. These, together with qualitative considerations, helped us to determine the scope of our assurance engagement, the nature, timing and extent of our assurance procedures and to evaluate the effect of misstatements, both individually and in aggregate on the Disclosure Information as a whole.

Scope

Our procedures included analytical procedures, evaluating the appropriateness of assumptions used and whether they have been consistently applied, agreement of the Disclosure Information to, or reconciling with, source systems and underlying records, an assessment of the significant judgements made by the Company in the preparation of the Disclosure Information and valuing the related party transactions, and evaluation of the overall adequacy of the presentation of supporting information and explanations.

These procedures have been undertaken to form an opinion as to whether the Company has complied, in all material respects, with the Determination in the preparation of the Disclosure

Information for the year ended 31 March 2024, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

Key Assurance Matters

Key assurance matters are those matters that, in our professional judgement, were of most significance in carrying out the assurance engagement during the current disclosure year. These matters were addressed in the context of our assurance engagement as a whole, and in forming our opinion. We do not provide a separate opinion on these matters. In addition to the matter described in the Basis of Qualified Opinion section of our report, we have determined the matters described below to be Key Assurance Matters.

Key Assurance Matter	How our procedures addressed the key assurance matter
Regulatory Asset Base (RAB) The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of the Company's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination. It is a measure which is used widely and is key to measuring the Company's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the IM Determination, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration. Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination. Our procedures over the regulatory asset base included the following: **Assets commissioned** ● We considered the nature of the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB; ● We inspected the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB; ● We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions disclosed in the audited annual financial statements and investigated any material reconciling items; and ● We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification. **Depreciation** ● For assets with no standard asset lives we assessed the reasonableness of the lives used by reference to the accounting depreciation rates used in preparing the financial statements; ● We have performed a reasonableness test to ensure regulatory depreciation expense is calculated in line with IM Determination clause 2.2.5

Key Assurance Matter	How our procedures addressed the key assurance matter
	● We compared the spreadsheet formula utilised to calculate regulatory depreciation expense with IM Determination clause 2.2.5; and ● We compared the standard asset lives by asset category to those set out in the IM Determination. **Revaluation** ● We recalculated the revaluation rate set out in the IM Determination using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; and ● We tested the mathematical accuracy of the revaluation calculation performed by management. **Disposals** ● We considered the nature of the asset disposals within the accounting fixed asset register and tested a sample of RAB disposals to ensure disposals in the RAB meet the definition of a disposal per the IM Determination.
Cost & Asset Allocation The Determination relates to information concerning the supply of electricity distribution services. In addition to the regulated supply of electricity, the Company also supplies customers with other unregulated services such as Metering services. As set out in schedules 5d, 5e, 5f and 5g, costs and asset values that relate to electricity distribution services regulated under the Determination should comprise: - All of the costs directly attributable to the regulated goods or services; and - An allocated portion of the costs that are not directly attributable. The IM Determination set out rules and processes for allocating costs and assets which are not directly attributable to either regulated or unregulated services. A number of screening tests apply which	We obtained an understanding of the Company's cost and asset allocation processes and the methodologies applied. **Our procedures over cost and asset allocation included:** ● Reconciling the regulated and unregulated financial information to the audited financial statements; **Classification as directly/not directly attributable** ● Considering the appropriateness of the costs allocated as directly attributable, based on the nature and our understanding of the business to determine the reasonableness of the directly attributable classification; ● Testing a sample of transactions to ensure their classification as either directly attributable or not directly attributable costs are appropriate and in line with the Determination; ● Inspecting the fixed asset register to identify any asset classes which based on their nature and our understanding of the business could be considered assets directly attributable to a specific business unit; ● Testing a sample of assets commissioned to ensure their classification as either directly

Key Assurance Matter	How our procedures addressed the key assurance matter
must be considered when deciding on the appropriate allocation method. The Company has applied the Accounting-Based Allocation Approach Methodology (ABAA) utilising proxy cost and asset allocators to allocate the asset values and operating costs that are not directly attributable where causal relationships could not be identified. Given the judgement involved in the application of the cost and asset allocation methodologies we consider it a key assurance matter.	attributable or not directly attributable are appropriate and in line with the Determination; **Appropriateness of the allocators used for not directly attributable costs and assets** ● Considering the appropriateness of the cost and asset proxy allocators used in applying the ABAA to not directly attributable costs including inspecting supporting documentation and recalculating proxy allocators; ● Understanding why causal relationships could not be identified in allocating some costs or assets and ensuring appropriate disclosure has been included outlining these in Schedule 14; ● Recalculating the split between not directly attributable costs and asset values allocated to electricity distribution services and non-electricity distribution services.
Related party transactions Disclosures over related party transactions including related party relationships, procurement policies/processes, application of these policies/processes and examples of market testing of transaction terms as required under the Determination and the IM Determination are set out in Appendix A. The Determination and the IM Determination require the Company to value its transactions with related parties, disclosed in Schedule 5b, in accordance with the principles-based approach to the arm's length valuation rule. This rule states that the value of goods or services acquired from a related party cannot be greater than if it had been acquired under the terms of an arm's length transaction with an unrelated party, nor may it exceed the actual cost to the related party. A sale or supply to a related party cannot be valued at an amount less than if it had been sold or supplied under the terms of an arm's-length transaction with an unrelated party. Arm's-length valuation, as defined in the IM Determination, is the value at which a transaction, with the same terms and	We have obtained an understanding of the compliance requirements relevant to related party transactions as set out in the Determination and the IM Determination. We have ensured Schedule 5(b) and Appendix A includes all required disclosures including current procurement policies, descriptions of how they are applied in practice, representative example transactions and when and how market testing was last performed. Our procedures over the related party transactions included the following: **Completeness and accuracy of related party relationships and transactions** We have tested the completeness and accuracy of the related party relationships and transactions by: ● Agreeing the disclosures within Schedule 5(b) to the audited financial statements for the year ended 31 March 2024 and to the accounting records, investigating any material differences and determining whether any such differences are justified; and ● Applying our understanding of the business structure against the related party definition in IM Determination clause 1.1.4(2)(b) to assess management's identification of any "unregulated parts" of the entity.

Key Assurance Matter	How our procedures addressed the key assurance matter
conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests. The Company applies the consolidation (or cost-based) approach for demonstrating compliance with the general valuation principles under the Determination and the IMs. The determinations presume that where the transaction is valued at the cost normally incurred by the related party, and provided this is fair and reasonable, it may be treated as if it was an arm's length transaction under the consolidation approach (i.e. no profit margin included). For those transactions where the consolidation approach is not applied the Company is required to use an objective and independent measure to demonstrate compliance with the arm's-length principle. In the absence of an active market for similar transactions, assigning an objective arm's length value to a related party transaction is difficult and requires significant judgement. We have identified related party transactions at arm's-length as a key assurance matter due to the judgement involved.	**Practical application of procurement policies** ● Testing a sample of operating expenditure and capital expenditure transactions disclosed in Schedule 5(b) by inspecting supporting documentation to determine compliance with the disclosed procurement policy and practices. **Arm's length valuation rule** We inquired with management and applied our understanding of the business to identify the types of transactions accounted for under the consolidation approach, and; ● Agreed the values of those transactions disclosed in Schedule 5(b) to those accounted for after elimination of intercompany profit within the Company audited financial statements; and ● Considered whether the costs incurred from related parties, under the consolidation approach, were fair and reasonable by testing controls around the approval of expenses on a sample basis and monitoring actual costs against budgets and the asset management plan. For those related party transactions not accounted for under the consolidation approach, we obtained the Company's assessment of the available independent and objective measures used in supporting the arm's length valuation principle and re-performed the calculations and agreed key inputs and assumptions to supporting documentation for a sample of transactions.

Directors' Responsibilities

The Directors are responsible on behalf of the Company for compliance with the Determination and the valuation of related party transactions in accordance with the Determination, for the identification of risks that may threaten such compliance, controls that would mitigate those risks, and monitoring the Company's ongoing compliance.

Our Independence and Quality Management

We have complied with the Professional and Ethical Standard 1 *International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand)* or other professional requirements, or requirements in law or regulation, that are at least as demanding, which include independence and other requirements founded on the fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

We apply Professional and Ethical Standard 3 *Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements*, which 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.

We are independent of the Company. Our firm carries out other services for the Company in the areas of the annual audit of the entity's financial statements and assurance over compliance with regulatory requirements of the Commerce Act 1986. The provision of these other services has not impaired our independence.

Assurance Practitioner's responsibilities

Our responsibility is to express an opinion on whether the Company has complied, in all material respects, with the Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2024 and on whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

Our engagement has been conducted in accordance with ISAE (NZ) 3000 (Revised) and SAE 3100 (Revised) which require that we plan and perform our procedures to obtain reasonable assurance about whether the Company has complied in all material respects with the Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2024, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

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

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. A reasonable assurance engagement for the disclosure year ended 31 March 2024 does not provide assurance on whether compliance with the Determination and the IM Determination will continue in the future.

Use of Report

This report has been prepared for the Directors and the Commerce Commission in accordance with clause 2.8.1(1) of the Determination and is provided solely to assist you in establishing that compliance requirements have been met.

Our report should not be used for any other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility for any reliance on this report to anyone other than the Directors of the Company, as a body, and the Commerce Commission, or for any purpose other than that for which it was prepared.

The engagement partner on the assurance engagement resulting in this independent auditor's report is Elizabeth Adriana (Adri) Smit.

PricewaterhouseCoopers.

Chartered Accountants
30 August 2024

Christchurch, New Zealand