INFORMATION DISCLOSURE PREPARED IN ACCORDANCE WITH ELECTRICITY INFORMATION DISCLOSURE DETERMINATION UNDER PART 4 OF THE COMMERCE ACT 1986

FOR THE YEAR ENDED 31 MARCH 2026

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1. INTRODUCTION

These Information Disclosure documents are submitted by Electricity Invercargill Limited pursuant to Part 4 of the Commerce Act 1986 in accordance with:

- The Electricity Information Disclosure Determination 2012 (consolidated in 2023), issued 6 July 2023.
- The Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 2020), issued 20 May 2020.
- The Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024.
- The Electricity Distribution Information Disclosure (Related Party Transaction Threshold) Amendment Determination 2026.

2. INFORMATION DISCLOSURE DISCLAIMER

The information disclosed in this Information Disclosure package issued by Electricity Invercargill Limited has been prepared in accordance with the Determination listed above.

The Determination requires the information to be disclosed in the manner it is presented.

The information should not be used for any other purposes than that intended under the Determination.

The financial information presented is for the electricity distribution business as described within the Determination.

Due to rounding and automatic calculations in the spreadsheets there may be minor summing variances.

3. SCHEDULES

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

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	25,126	355	100,361	9,492	39,993
Network	8,799	124	35,146	3,324	14,005
Non-network	16,327	231	65,215	6,168	25,988
Expenditure on assets	27,735	392	110,781	10,478	44,146
Network	27,735	392	110,781	10,478	44,146
Non-network	–	–	–	–	–

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	92,886	1,314
Standard consumer line charge revenue	92,886	1,314
Non-standard consumer line charge revenue	–	–

1(iii): Service intensity measures

Demand density	93	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	378	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	27	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	14,146	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	6,319	27.04%
Pass-through and recoverable costs excluding financial incentives and wash-ups	5,528	23.66%
Total depreciation	4,592	19.65%
Total revaluations	3,664	15.68%
Regulatory tax allowance	1,901	8.14%
Regulatory profit/(loss) including financial incentives and wash-ups	8,691	37.19%
Total regulatory income	23,366	

1(v): Reliability

Interruption rate	7.21	*Interruptions per 100 circuit km*

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

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	6.22%	4.85%	7.16%
11	Excluding revenue earned from financial incentives	6.35%	4.84%	7.37%
12	Excluding revenue earned from financial incentives and wash-ups	6.45%	4.93%	6.36%
13				
14	**Mid-point estimate of post tax WACC**	6.05%	6.18%	5.90%
15	25th percentile estimate	5.37%	5.50%	5.17%
16	75th percentile estimate	6.73%	6.86%	6.62%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	6.92%	5.57%	7.80%
21	Excluding revenue earned from financial incentives	7.05%	5.56%	8.01%
22	Excluding revenue earned from financial incentives and wash-ups	7.15%	5.65%	6.99%
23				
24	**WACC rate used to set regulatory price path**	4.57%	4.57%	7.10%
25				
26	**Mid-point estimate of vanilla WACC**	6.75%	6.90%	6.53%
27	25th percentile estimate	6.07%	6.22%	5.81%
28	75th percentile estimate	7.43%	7.58%	7.26%
29				

30	**2(ii): Information Supporting the ROI**		($000)	
31				
32	Total opening RAB value	119,114		
33	*plus* Opening deferred tax	(7,851)		
34	**Opening RIV**		111,263	
35				
36	**Line charge revenue**		23,360	
37				
38	Expenses cash outflow	11,847		
39	*add* Assets commissioned	6,255		
40	*less* Asset disposals	95		
41	*add* Tax payments	1,151		
42	*less* Other regulated income	6		
43	**Mid-year net cash outflows**		19,152	
44				
45	**Term credit spread differential allowance**		–	
46				
47	Total closing RAB value	124,346		
48	*less* Adjustment resulting from asset allocation	(0)		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(8,601)		
51	**Closing RIV**		115,745	
52				
53	**ROI – comparable to a vanilla WACC**			7.80%
54				
55	Leverage (%)			41%
56	Cost of debt assumption (%)			5.56%
57	Corporate tax rate (%)			28%
58				
59	**ROI – comparable to a post tax WACC**			7.16%
60				

2(iii): Information Supporting the Monthly ROI

Opening RIV						N/A
	Line charge revenue	**Expenses cash outflow**	**Assets commissioned**	**Asset disposals**	**Other regulated income**	**Monthly net cash outflows**
April						–
May						–
June						–
July						–
August						–
September						–
October						–
November						–
December						–
January						–
February						–
March						–
Total	–	–	–	–	–	–
Tax payments						N/A
Term credit spread differential allowance						N/A
Closing RIV						N/A
Monthly ROI – comparable to a vanilla WACC						N/A
Monthly ROI – comparable to a post tax WACC						N/A

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

Year-end ROI – comparable to a vanilla WACC	6.53%
Year-end ROI – comparable to a post tax WACC	5.89%

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

2(v): Financial Incentives and Wash-Ups

IRIS incentive adjustment	(311)	
Purchased assets – avoided transmission charge	–	
Innovation and non-traditional solutions recovered amount	–	
Quality incentive adjustment	3	
Other CPP financial incentives	–	
Financial incentives		(308)
Impact of financial incentives on ROI		–0.20%
Input methodology claw-back	–	
CPP application recoverable costs	–	
CPP Urgent project allowance	–	Not Required before DY2
Reopener event allowance	–	Not Required before DY2
Wash-up draw down amount	1,529	Not Required before DY2
Other CPP wash-ups	–	
Wash-up costs		1,529
Impact of wash-up costs on ROI		1.01%

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

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

3(i): Regulatory Profit

sch ref			($000)
8		**Income**	
9		Line charge revenue	23,360
10	*plus*	Gains / (losses) on asset disposals	(88)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	94
12			
13		**Total regulatory income**	23,366
14		**Expenses**	
15	*less*	Operational expenditure	6,319
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	5,528
18			
19		**Operating surplus / (deficit)**	11,519
20			
21	*less*	Total depreciation	4,592
22			
23	*plus*	Total revaluations	3,664
24			
25		**Regulatory profit / (loss) before tax**	10,592
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	1,901
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	8,691
32			

3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups

sch ref		($000)	
34	**Pass through costs**		
35	Electricity lines service charge payable to Transpower	4,805	Not Required before DY
36	Transpower new investment contract charges	340	Not Required before DY
37	System operator services	–	Not Required before DY
38	Rates	233	
39	Commerce Act levies	52	
40	Industry levies	73	
41	CPP or DPP specified pass-through costs	–	
42	**Recoverable costs excluding financial incentives and wash-ups**		
43	Independent engineer costs	–	Not Required before DY
44	FENZ levies	25	Not Required before DY
45	Extended reserves allowance	–	
46	Other CPP recoverable costs excluding financial incentives and wash-ups	–	
47	**Pass-through and recoverable costs excluding financial incentives and wash-ups**		5,528
48			

3(iv): Merger and Acquisition Expenditure

sch ref		($000)
51	Merger and acquisition expenditure	–
52		

53 *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)*

3(v): Other Disclosures

sch ref		($000)
56	Self-insurance allowance	–

SCHEDULE 3a: REPORT ON INCREMENTAL ROLLING INCENTIVE SCHEME

This schedule requires information on the calculation of IRIS incentive amounts. All non-exempt EDBs must complete this section.
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.
Please note; only the white cells should be filled in (i.e. F7 - J7, F10 - J12, F15 - J17). Forecast values should be filled in for all years, actual values should be filled in for all years where known.

Section	Row	Context	Category1	Category2	RY1	RY2	RY3	RY4	RY5	Total over / (under) spend
3a: Incremental Rolling Incentive Scheme	7	**Current Year**		**Current Year**	CY	CY+1	CY+2	CY+3	CY+4	

Section	Row	Context	Category1	Category2	RY1 ($000)	RY2 ($000)	RY3 ($000)	RY4 ($000)	RY5 ($000)	Total over / (under) spend
3a: Incremental Rolling Incentive Scheme	10		Opex incentive amounts	Forecast opex	6,855	7,064	7,306	7,562	7,829	
3a: Incremental Rolling Incentive Scheme	11		Opex incentive amounts	Actual opex	6,319	-	-	-	-	
3a: Incremental Rolling Incentive Scheme	12 +		Opex incentive amounts	Plus lease payments	-	-	-	-	-	
3a: Incremental Rolling Incentive Scheme	13		Opex incentive amounts	Actual opex for IRIS	6,319	-	-	-	-	
3a: Incremental Rolling Incentive Scheme	14		Opex incentive amounts	Expenditure variance to opex allowance	(536)	-	-	-	-	(536)
3a: Incremental Rolling Incentive Scheme	15		Capex incentive amounts	Forecast aggregate value of commissioned assets	6,949	9,274	9,939	8,197	9,826	
3a: Incremental Rolling Incentive Scheme	16		Capex incentive amounts	Actual commissioned assets	6,255	-	-	-	-	
3a: Incremental Rolling Incentive Scheme	17 -		Capex incentive amounts	Less right-of-use assets	-	-	-	-	-	
3a: Incremental Rolling Incentive Scheme	18		Capex incentive amounts	Actual commissioned assets for IRIS	6,255	-	-	-	-	
3a: Incremental Rolling Incentive Scheme	19		Capex incentive amounts	Expenditure variance to commissioned assets allowance	(694)	-	-	-	-	(694)

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

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)

		RAB CY-4 ($000)	RAB CY-3 ($000)	RAB CY-2 ($000)	RAB CY-1 ($000)	RAB CY ($000)
10	**Total opening RAB value**	91,117	99,905	107,300	113,034	119,114
12	*less* **Total depreciation**	3,495	3,729	4,044	4,315	4,592
14	*plus* **Total revaluations**	6,303	6,645	4,309	2,851	3,664
16	*plus* **Assets commissioned**	6,117	4,522	5,631	7,667	6,255
18	*less* **Asset disposals**	137	43	163	124	95
20	*plus* **Lost and found assets adjustment**	–	–	–	–	–
22	*plus* **Adjustment resulting from asset allocation**	(0)	0	0	(0)	(0)
24	**Total closing RAB value**	99,905	107,300	113,034	119,114	124,346

4(ii): Unallocated Regulatory Asset Base

			Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
29	**Total opening RAB value**			119,114		119,114
31	*less* **Total depreciation**			4,592		4,592
33	*plus* **Total revaluations**			3,664		3,664
35	*plus* Assets commissioned out of WUC	Not Required before DY2026	6,255		6,255	
36	Assets acquired (other than below)	Not Required before DY2026	–		–	
37	Assets acquired from a regulated supplier		–		–	
38	Assets acquired from a related party		–		–	
39	**Assets commissioned**			6,255		6,255
41	*less* Asset disposals (other than below)		95		95	
42	Asset disposals to a regulated supplier		–		–	
43	Asset disposals to a related party		–		–	
44	**Asset disposals**			95		95
46	*plus* **Lost and found assets adjustment**			–		–
48	*plus* **Adjustment resulting from asset allocation**					(0)
50	**Total closing RAB value**			124,346		124,346

** 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.*

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

55	CPI_4	1,339
56	$CPI_4{}^{-4}$	1,299
57	Revaluation rate (%)	3.08%

		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
61	Total opening RAB value	119,114		119,114	
62	*less* Opening value of fully depreciated, disposed and lost assets	113		113	
64	Total opening RAB value subject to revaluation	119,001		119,001	
65	**Total revaluations**		3,664		3,664

4(iv): Roll Forward of Works Under Construction

			Unallocated works under construction		Allocated works under construction	
69	**Works under construction—preceding disclosure year**	Not Required before DY2026		1,960		1,960
70	*plus* WUC capital expenditure	Not Required before DY2026				
71	WUC acquired from a regulated supplier	Not Required before DY2026	–		–	
72	WUC acquired from a related party	Not Required before DY2026	–		–	
73	WUC capital expenditure - other	Not Required before DY2026	6,975		6,975	
74	Total WUC capital expenditure	Not Required before DY2026	6,975		6,975	
75	*less* WUC capital contributions	Not Required before DY2026	389		389	
76	*less* WUC other revenue	Not Required before DY2026	–		–	
77	*less* Assets commissioned out of WUC	Not Required before DY2026	6,255		6,255	
78	*plus* Adjustment resulting from asset allocation	Not Required before DY2026				
79	**Works under construction - current disclosure year**	Not Required before DY2026		2,292		2,292
81	Highest rate of capitalised finance applied					–

4(v): Regulatory Depreciation

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Depreciation - standard	4,592		4,592	
Depreciation - no standard life assets	–		–	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		4,592		4,592

4(vi): Disclosure of Changes to Depreciation Profiles

($000 unless otherwise specified)

Asset or assets with changes to depreciation*	Reason for non-standard depreciation (text entry)	Depreciation charge for the period (RAB)	Closing RAB value under 'non-standard' depreciation	Closing RAB value under 'standard' depreciation

** include additional rows if needed*

4(vii): Disclosure by Asset Category

($000 unless otherwise specified)

		Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	Total
	Total opening RAB value	1,463	8,055	24,132	3,974	50,603	13,176	13,487	4,224	–	119,114
less	Total depreciation	48	249	937	119	1,877	559	533	270	–	4,592
plus	Total revaluations	45	248	743	122	1,558	403	415	130	–	3,664
plus	Assets commissioned	–	–	206	763	1,214	1,295	2,610	167	–	6,255
less	Asset disposals	–	–	–	–	–	95	–	–	–	95
plus	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
plus	Asset category transfers	–	–	–	–	–	–	–	–	–	–
	Total closing RAB value	1,460	8,054	24,145	4,742	51,497	14,220	15,979	4,250	–	124,346
	Asset Life										
	Weighted average remaining asset life	30.6	38.2	32.6	40.7	35.5	27.7	27.4	16.9	–	(years)
	Weighted average expected total asset life	40.3	57.1	50.4	59.9	58.6	45.0	39.1	34.0	–	(years)

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

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 2.8.

sch ref

5a(i): Regulatory Tax Allowance

sch ref					($000)
8		**Regulatory profit / (loss) before tax**			10,592
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	–	*	
12		Amortisation of initial differences in asset values	1,237		
13		Amortisation of revaluations	1,101		
14		**Total**			2,337
15					
16	*less*	Total revaluations	3,664		
17		Income included in regulatory profit / (loss) before tax but not taxable	–	*	
18		Discretionary discounts and customer rebates	–		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax	6	*	
20		Notional deductible interest	2,469		
21		**Total**			6,139
22					
23		**Regulatory taxable income**			6,790
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			6,790
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			1,901
30					

31 * Workings to be provided in Schedule 14

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).

5a(iii): Amortisation of Initial Difference in Asset Values

sch ref				($000)
35				
36		Opening unamortised initial differences in asset values	14,839	
37	*less*	Amortisation of initial differences in asset values	1,237	
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–	
39	*less*	Adjustment for unamortised initial differences in assets disposed	59	
40		Closing unamortised initial differences in asset values		13,544
41				
42		Opening weighted average remaining useful life of relevant assets (years)		12
43				

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	91,463	
	Adjusted depreciation	3,491	
	Total depreciation	4,592	
	Amortisation of revaluations		1,101

5a(v): Reconciliation of Tax Losses

			($000)
	Opening tax losses	–	
plus	Current period tax losses	–	
less	Utilised tax losses	–	
	Closing tax losses		–

5a(vi): Calculation of Deferred Tax Balance

			($000)
	Opening deferred tax	(7,851)	
plus	Tax effect of adjusted depreciation	978	
less	Tax effect of tax depreciation	1,504	
plus	Tax effect of other temporary differences*	97	
less	Tax effect of amortisation of initial differences in asset values	346	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–	
less	Deferred tax balance relating to assets disposed in the disclosure year	(26)	
plus	Deferred tax cost allocation adjustment	0	
	Closing deferred tax		(8,601)

5a(vii): Disclosure of Temporary Differences

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).

5a(viii): Regulatory Tax Asset Base Roll-Forward

			($000)
	Opening sum of regulatory tax asset values	50,224	
less	Tax depreciation	5,372	
plus	Regulatory tax asset value of assets commissioned	6,612	
less	Regulatory tax asset value of asset disposals	2	
plus	Lost and found assets adjustment	–	
plus	Adjustment resulting from asset allocation	–	
plus	Other adjustments to the RAB tax value	–	
	Closing sum of regulatory tax asset values		51,462

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

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

5b(i): Summary—Related Party Transactions

		($000)	($000)
8	**Total regulatory income**		–
10	**Market value of asset disposals**		–
12	Service interruptions and emergencies	–	
13	Vegetation management	–	
14	Routine and corrective maintenance and inspection	–	
15	Asset replacement and renewal (opex)	–	
16	**Network opex**		–
17	Business support	355	
18	System operations and network support	–	
19	Non-network solutions provided by a related party or third party	–	
20	**Operational expenditure**		355
21	Consumer connection	–	
22	System growth	–	
23	Asset replacement and renewal (capex)	–	
24	Asset relocations	–	
25	Quality of supply	–	
26	Legislative and regulatory	–	
27	Other reliability, safety and environment	–	
28	**Expenditure on non-network assets**		–
29	**Expenditure on assets**		–
30	Cost of financing		–
31	Value of capital contributions		7
32	Value of vested assets		–
33	**Capital Expenditure**		(7)
34	**Total expenditure**		348
36	**Other related party transactions**		204

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)
39	Invercargill City Holdings	Business support	157
40	Directors	Business support	198
41			
42			
43			
44			
45			
46			
47			
48			
49			
50			
51			
52			
53			
54	Total value of related party transactions		355

55 ** include additional rows if needed*

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

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

10 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 (NZ	Term Credit Spread Difference	Debt issue cost readjustment
11								
12								
13								
14								
15								
16 *Total*						–	–	–

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	41%	
24 Average opening and closing RAB values	–	
25 **Attribution Rate (%)**		–
26		
27 **Term credit spread differential allowance**		–

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2026

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(i): Operating Cost Allocations

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		846			
Not directly attributable		–		–	
Total attributable to regulated service		846			
Vegetation management					
Directly attributable		5			
Not directly attributable		–		–	
Total attributable to regulated service		5			
Routine and corrective maintenance and inspection					
Directly attributable		1,361			
Not directly attributable		–		–	
Total attributable to regulated service		1,361			
Asset replacement and renewal					
Directly attributable		0			
Not directly attributable		–		–	
Total attributable to regulated service		0			
Non-network solutions provided by a related party or third party					
Directly attributable		–			
Not directly attributable		–		–	
Total attributable to regulated service		–			
System operations and network support					
Directly attributable		1,675			
Not directly attributable		–		–	
Total attributable to regulated service		1,675			
Business support					
Directly attributable		1,614			
Not directly attributable		817	47	864	
Total attributable to regulated service		2,431			
Operating costs directly attributable		5,502			
Operating costs not directly attributable	–	817	47	864	–
Operational expenditure		6,319			

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	5,503
Not directly attributable	–
Total attributable to regulated service	5,503
Recoverable costs	
Directly attributable	25
Not directly attributable	
Total attributable to regulated service	25

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

Change in cost allocation 1

		($000) CY-1	($000) Current Year (CY)
Cost category			
Original allocator or line items	Original allocation		
New allocator or line items	New allocation		
	Difference	–	–

Rationale for change

Change in cost allocation 2

		($000) CY-1	($000) Current Year (CY)
Cost category			
Original allocator or line items	Original allocation		
New allocator or line items	New allocation		
	Difference	–	–

Rationale for change

Change in cost allocation 3

		($000) CY-1	($000) Current Year (CY)
Cost category			
Original allocator or line items	Original allocation		
New allocator or line items	New allocation		
	Difference	–	–

Rationale for change

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

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

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

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	1,460
Not directly attributable	–
Total attributable to regulated service	1,460
Subtransmission cables	
Directly attributable	8,054
Not directly attributable	–
Total attributable to regulated service	8,054
Zone substations	
Directly attributable	24,145
Not directly attributable	–
Total attributable to regulated service	24,145
Distribution and LV lines	
Directly attributable	4,742
Not directly attributable	–
Total attributable to regulated service	4,742
Distribution and LV cables	
Directly attributable	51,497
Not directly attributable	–
Total attributable to regulated service	51,497
Distribution substations and transformers	
Directly attributable	14,220
Not directly attributable	–
Total attributable to regulated service	14,220
Distribution switchgear	
Directly attributable	15,979
Not directly attributable	–
Total attributable to regulated service	15,979
Other network assets	
Directly attributable	4,250
Not directly attributable	–
Total attributable to regulated service	4,250
Non-network assets	
Directly attributable	–
Not directly attributable	–
Total attributable to regulated service	–
Regulated service asset value directly attributable	124,346
Regulated service asset value not directly attributable	–
Total closing RAB value	124,346

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

Change in asset value allocation 1

			($000) CY-1	Current Year (CY)
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–

Rationale for change

Change in asset value allocation 2

			($000) CY-1	Current Year (CY)
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–

Rationale for change

Change in asset value allocation 3

			($000) CY-1	Current Year (CY)
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–

Rationale for change

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

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

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

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

sch ref

	Line Item *	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%): Electricity distribution services	Allocator Metric (%): Non-electricity distribution services	Value allocated ($000): Arm's length deduction	Value allocated ($000): Electricity distribution services	Value allocated ($000): Non-electricity distribution services	Value allocated ($000): Total	OVABAA allocation increase ($000)
11	**Service interruptions and emergencies**										
12										-	
13										-	
14										-	
15										-	
16	**Not directly attributable**						-	-	-	-	-
17	**Vegetation management**										
18										-	
19										-	
20										-	
21										-	
22	**Not directly attributable**						-	-	-	-	-
23	**Routine and corrective maintenance and inspection**										
24										-	
25										-	
26										-	
27										-	
28	**Not directly attributable**						-	-	-	-	-
29	**Asset replacement and renewal**										
30										-	
31										-	
32										-	
33										-	
34	**Not directly attributable**						-	-	-	-	-
35											
36	**Non-network solutions provided by a related party or third party** *Not required before DY2025*										
37										-	
38										-	
39										-	
40										-	
41	**Not directly attributable**						-	-	-	-	-
43	**System operations and network support**										
44										-	
45										-	
46										-	
47										-	
48	**Not directly attributable**						-	-	-	-	-
49	**Business support**										
50	Administration Expenses	ABAA	Revenue	Proxy	94.52%	5.48%	-	817	47	864	
51										-	
52										-	
53										-	
54	**Not directly attributable**						-	817	47	864	-
55											
56											
57	**Operating costs not directly attributable**						-	817	47	864	-
58	**Pass through and recoverable costs**										
59	**Pass through costs**										
60										-	
61										-	
62										-	
63										-	
64	**Not directly attributable**						-	-	-	-	-
65	**Recoverable costs**										
66										-	
67										-	
68										-	
69										-	
70	**Not directly attributable**						-	-	-	-	-

71 ** include additional rows if needed*

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

This schedule requires additional detail on the asset allocation methodology applied in allocating asset values that are not directly attributable, to support the information provided in Schedule 5e (Report on Asset Allocations). This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

	Line Item*	Allocation methodology type	Allocator	Allocator type	Allocator Metric (%): Electricity distribution services	Allocator Metric (%): Non-electricity distribution services	Value allocated ($000): Arm's length deduction	Value allocated ($000): Electricity distribution services	Value allocated ($000): Non-electricity distribution services	Value allocated ($000): Total	OVABAA allocation increase ($000)
11	**Subtransmission lines**										
12										-	
13										-	
14										-	
15										-	
16	**Not directly attributable**						-	-	-	-	-
17	**Subtransmission cables**										
18										-	
19										-	
20										-	
21										-	
22	**Not directly attributable**						-	-	-	-	-
23	**Zone substations**										
24										-	
25										-	
26										-	
27										-	
28	**Not directly attributable**						-	-	-	-	-
29	**Distribution and LV lines**										
30										-	
31										-	
32										-	
33										-	
34	**Not directly attributable**						-	-	-	-	-
35	**Distribution and LV cables**										
36										-	
37										-	
38										-	
39										-	
40	**Not directly attributable**						-	-	-	-	-
41											
42	**Distribution substations and transformers**										
43										-	
44										-	
45										-	
46										-	
47	**Not directly attributable**						-	-	-	-	-
48											
49	**Distribution switchgear**										
50										-	
51										-	
52										-	
53										-	
54	**Not directly attributable**						-	-	-	-	-
55	**Other network assets**										
56										-	
57										-	
58										-	
59										-	
60	**Not directly attributable**						-	-	-	-	-
61	**Non-network assets**										
62										-	
63										-	
64										-	
65										-	
66	**Not directly attributable**						-	-	-	-	-
67											
68	**Regulated service asset value not directly attributable**						-	-	-		
69	** include additional rows if needed*										

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

SCHEDULE 5h: REPORT ON CYBERSECURITY EXPENDITURE

This schedule requires details on the cybersecurity expenditure for various categories. This schedule is not required to be publicly disclosed, but must be disclosed to the Commission.
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

5h(i): Actual Expenditure Capex (where known)

Cybersecurity (Commission only)	–

5h(ii): Actual Expenditure Opex (where known)

Cybersecurity (Commission only)	46

5h(iii): Actual vs Forecast (where known)

	Target ($000)	Actual ($000)	% variance
Cybersecurity (Commission only)	39	46	18%

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

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**			
8		Consumer connection		852
9		System growth		–
10		Asset replacement and renewal		5,207
11		Asset relocations		32
12		Reliability, safety and environment:		
13		Quality of supply	31	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	854	
16		**Total reliability, safety and environment**		884
17		**Expenditure on network assets**		6,975
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		6,975
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		389
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		6,586

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

sch ref			($000)	($000)
31	**6a(iii): Consumer Connection**			
32		*Consumer types defined by EDB**		
33		Customer Connections < 20 kVA	125	
34		Customer Connections 21 - 99 kVA	27	
35		Customer Connections > 100 kVA	680	
36		New Subdivisions	20	
37				
38		** include additional rows if needed*		
39		**Consumer connection expenditure**		852
40				
41	*less*	Capital contributions funding consumer connection expenditure	389	
42		**Consumer connection less capital contributions**		463

sch ref			System Growth ($000)	Asset Replacement and Renewal ($000)
43	**6a(iv): System Growth and Asset Replacement and Renewal**			
44				
45				
46		Subtransmission	–	–
47		Zone substations	–	45
48		Distribution and LV lines	–	118
49		Distribution and LV cables	–	1,181
50		Distribution substations and transformers	–	1,156
51		Distribution switchgear	–	2,708
52		Other network assets	–	–
53		**System growth and asset replacement and renewal expenditure**	–	5,207
54	*less*	Capital contributions funding system growth and asset replacement and renewal	–	–
55		**System growth and asset replacement and renewal less capital contributions**	–	5,207
56				

sch ref			($000)	($000)
57	**6a(v): Asset Relocations**			
58		*Project or programme**		
59			–	
60			–	
61			–	
62			–	
63			–	
64		** include additional rows if needed*		
65		All other projects or programmes - asset relocations	32	
66		**Asset relocations expenditure**		32
67	*less*	Capital contributions funding asset relocations	–	
68		**Asset relocations less capital contributions**		32

69

70 **6a(vi): Quality of Supply**

	Project or programme*	($000)	($000)
71			
72	Fault Indicator Project	29	
73		–	
74		–	
75		–	
76		–	
77	* include additional rows if needed		
78	All other projects programmes - quality of supply	2	
79	**Quality of supply expenditure**		31
80	*less* Capital contributions funding quality of supply	–	
81	**Quality of supply less capital contributions**		31

82 **6a(vii): Legislative and Regulatory**

	Project or programme*	($000)	($000)
83			
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**

	Project or programme*	($000)	($000)
95			
96	Earth Upgrades	344	
97	Pillar Box Lid Upgrade	55	
98	Fibre Installation	58	
99	LV Tie Point Disconnectors	397	
100			
101	* include additional rows if needed		
102	All other projects or programmes - other reliability, safety and environment		
103	**Other reliability, safety and environment expenditure**		854
104	*less* Capital contributions funding other reliability, safety and environment	–	
105	**Other reliability, safety and environment less capital contributions**		854
106			

107 **6a(ix): Non-Network Assets**

108 **Routine expenditure**

	Project or programme*	($000)	($000)
109			
110		–	
111		–	
112		–	
113		–	
114		–	
115	* include additional rows if needed		
116	All other projects or programmes - routine expenditure	–	
117	**Routine expenditure**		–

118 **Atypical expenditure**

	Project or programme*	($000)	($000)
119			
120		–	
121		–	
122		–	
123		–	
124		–	
125	* include additional rows if needed		
126	All other projects or programmes - atypical expenditure	–	
127	**Atypical expenditure**		–
128			
129	**Expenditure on non-network assets**		–

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

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

This schedule requires a breakdown of operational expenditure incurred in the disclosure year.
EDBs must provide explanatory comment on their operational expenditure in Schedule 14 (Explanatory notes to templates). This includes explanatory comment on any atypical operational expenditure and assets replaced or renewed as part of asset replacement and renewal operational expenditure, and additional information on insurance.
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref		($000)	($000)
7	**6b(i): Operational Expenditure** *Not Required before DY2026*		
8	Service interruptions and emergencies:		
9	Vegetation-related	–	
10	Other	846	
11	**Total service interruptions and emergencies**	846	
12	Vegetation management:		
13	Assessment and notification costs	–	
14	Felling or trimming vegetation - in-zone	–	
15	Felling or trimming vegetation - out-of-zone	–	
16	Other	5	
17	**Total vegetation management**	5	
18			
19	Routine and corrective maintenance and inspection:	1,361	
20	Asset replacement and renewal	0	
21	**Network opex**		2,213
22	Non-network solutions provided by a related party or third party	–	
23	System operations and network support	1,675	
24	Business support	2,431	
25	**Non-network opex**		4,106
26			
27	**Operational expenditure**		6,319
28	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
29	Energy efficiency and demand side management, reduction of energy losses		150
30	Direct billing*		–
31	Research and development		–
32	Insurance		231
33	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

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

		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	23,676	23,360	(1%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	850	852	0%
11	System growth	–	–	–
12	Asset replacement and renewal	5,582	5,207	(7%)
13	Asset relocations	7	32	330%
14	Reliability, safety and environment:			
15	Quality of supply	175	31	(83%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	686	854	24%
18	**Total reliability, safety and environment**	861	884	3%
19	**Expenditure on network assets**	7,301	6,975	(4%)
20	Expenditure on non-network assets	–	–	–
21	Expenditure on assets	7,301	6,975	(4%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	604	846	40%
24	Vegetation management	2	5	104%
25	Routine and corrective maintenance and inspection	1,616	1,361	(16%)
26	Asset replacement and renewal	183	0	(100%)
27	**Network opex**	2,406	2,213	(8%)
28	Non-network solutions provided by a related party or third party	–	–	–
29	System operations and network support	1,994	1,675	(16%)
30	Business support	2,517	2,431	(3%)
31	**Non-network opex**	4,511	4,106	(9%)
32	**Operational expenditure**	6,917	6,319	(9%)
33	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
34	Energy efficiency and demand side management, reduction of energy losses	–	–	–
35	Overhead to underground conversion	–	–	–
36	Research and development	–	–	–
37				
38	**7(v): Subcomponents of Operational Expenditure (where known)**			
39	Energy efficiency and demand side management, reduction of energy losses	150	150	–
40	Direct billing	–	–	–
41	Research and development	–	–	–
42	Insurance	543	231	(57%)
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
For Year Ended
Network / Sub-Network Name

Electricity Invercargill Limited
31 March 2026

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 breaks of this schedule to assist with readability if needed.

8(i): Billed Quantities by Price Component

Billed quantities by price component

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)	Daily fixed charge - $/day		All-inclusive TOU peak charge - $/kWh		All-inclusive TOU shoulder charge - $/kWh		All-inclusive TOU off-peak charge - $/kWh		Individual contract - $/kWh		Individual contract - $/day	
Standardised price component																
EDB defined price component							Purchases Peak Volume at GXP		Purchases Shoulder Volume at GXP		Purchases Night Volume at GXP		Sales Day Volume at Customer Meter			
					Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity
Low user	Residential	Standard	6,368	40,195	2,233,501	2,233,501	14,814,452	14,814,452	14,803,897	14,803,897	10,258,000	10,258,000				
Residential	Residential	Standard	9,307	89,902	3,088,097	3,088,097	27,621,348	27,621,348	22,576,717	22,576,717	22,871,522	22,871,522				
General	Commercial	Standard	1,368	44,974	708,279	708,279	19,666,009	19,666,009	17,470,774	17,470,774	11,326,177	11,326,177				
Individual Non Half Hour	Commercial	Standard	25	2,874			1,203,820	1,203,820	1,069,441	1,069,441	754,614	754,614			6,737	6,737
Individual Half Hour	Industrial	Standard	167	71,248									11,518,252	11,518,252	53,956	53,956
Add extra rows for additional consumer groups or price category codes as necessary																
Standard consumer totals			17,238	251,693	6,029,787	6,029,787	75,229,629	75,229,629	66,920,817	66,920,817	47,214,729	47,214,729	11,518,252	11,518,252	59,843	59,843
Non-standard consumer totals			–	–	–	–	–	–	–	–	–	–	–	–	–	–
Total for all consumers			17,238	251,693	6,029,787	6,029,787	75,229,629	75,229,629	66,920,817	66,920,817	47,214,729	47,214,729	11,518,252	11,518,252	59,843	59,843

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

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

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group [specify]	Total line charge revenue in disclosure year	Consumer discounts ($000)			Total distribution line charge revenue	Total transmission line charge revenue	Line charge revenues ($000) by price component																																			
				Standardised price component	[Select one]						Standardised price component	Daily fixed charge - $/day			All-inclusive TOU peak charge - $/kWh			All-inclusive TOU shoulder charge - $/kWh			All-inclusive TOU off-peak charge - $/kWh			Individual contract - $/kWh			Individual contract - $/day			Add extra columns for additional line charge revenues by price component as necessary
				EDB defined price component							EDB defined price component				Purchases Peak Volume at GXP			Purchases Shoulder Volume at GXP			Purchases Night Volume at GXP			Sales Day Volume at Customer Meter						
					Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)					Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	
Low user	Residential	Standard	$4,622				–	$2,628	$994		$562	$994	$1,556	$1,791	–	$1,791	$1,185	–	$1,185	$103	–	$103			–			–	
Residential	Residential	Standard	$8,274				–	$7,687	$1,587		$2,756	$1,587	$4,342	$2,874	–	$2,874	$1,858	–	$1,858	$139	–	$139			–			–	
General	Commercial	Standard	$5,312				–	$4,208	$1,124		$1,611	$1,124	$2,735	$1,502	–	$1,502	$972	–	$972	$123	–	$123			–			–	
Individual Non Half hour	Commercial	Standard	$214				–	$175	$82		–	–	–	$56	$12	$68	$46	$10	$56	$8	–	$8			–	$48	$49	$97	
Individual Half Hour	Industrial	Standard	$1,867				–	$2,503	$1,358		–	–	–	–	–	–	–	–	–	–	–	–	$1,148	$98	$1,246	$1,161	$1,240	$2,420	
			–				–	–	–				–			–			–			–			–			–	
			–				–	–	–				–			–			–			–			–			–	
			–				–	–	–				–			–			–			–			–			–	
			–				–	–	–				–			–			–			–			–			–	
			–				–	–	–				–			–			–			–			–			–	
Add extra rows for additional consumer groups or price category codes as necessary																													
		Standard consumer totals	$21,060		–	–	–	$18,210	$5,145		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
		Non-standard consumer totals	–		–	–	–	–	–		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
		Total for all consumers	$21,060		–	–	–	$18,210	$5,145		$4,879	$3,704	$8,583	$6,242	$12	$6,254	$4,060	$10	$4,070	$472	–	$472	$1,148	$98	$1,246	$1,208	$1,289	$2,518	

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end: –

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref

9a: Asset Register

8	Voltage	Asset category	Asset class	Unit	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.	759	769	10	3
10	All	Overhead Line	Wood poles	No.	185	184	(1)	4
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1	1	–	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	15	15	(0)	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	12	12	0	4
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.	5	5	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	N/A
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	7	7	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	6	6	–	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	8	8	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	N/A
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	53	53	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	N/A
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	7	7	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	21	21	(0)	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	68	69	1	3
39	HV	Distribution Cable	Distribution UG PILC	km	92	91	(2)	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.	2	2	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	63	58	(5)	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	306	304	(2)	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	9	8	(1)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	441	440	(1)	4
48	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	N/A
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	35	32	(3)	4
50	LV	LV Line	LV OH Conductor	km	30	30	0	3
51	LV	LV Cable	LV UG Cable	km	426	427	0	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	171	171	(0)	3
53	LV	Connections	OH/UG consumer service connections	No.	18,109	18,146	37	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	129	130	1	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	1	1	–	4
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2026
Network / Sub-network Name	

SCHEDULE 9b: ASSET AGE PROFILE

This schedule requires a summary of the age profile (based on year of installation) of the assets that make up the network, by asset category and asset class. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

9b: Asset Age Profile

8 Disclosure Year (year ended)

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-19	1940 –1945	1950 –1955	1960 –1965	1970 –1975	1980 –1985	1990 –1995	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	2026	2027	2028	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	–	–	–	305	6	–	1	3	4	2	–	6	3	4	2	11	5	26	97	35	74	17	25	26	31	8	8	7	10	10	13	16	9	1			3	769		3
11	All	Overhead Line	Wood poles	No.	–	–	–	132	1	–	2	13	11	4	6	6	4	2	–	1	1	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–			–	184		4
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	–	0	–	–	1	0	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	–			0	1		4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	5	1	4	–	–	–	–	–	–	–	0	–	–	–	–	–	–	5	–	–	–	–	–	0	0	–	0	–	–			–	15		4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	5	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	12		4
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	–		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	1	1	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–			–	5		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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	–		N/A
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	–	–	–			4	7		4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	–	1	–	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	3	–	–	–	–	–	–	–	–	–	–	–			–	6		4
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	–	–	–	–			–	8		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	–		N/A
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	11	11	–	3	–	–	1	–	–	–	–	–	–	–	–	–	–	1	18	–	–	–	–	5	3	–	–	–	–	–			–	53		4
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	1	1	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	1	1	–	–	–	1	–	–	–	–	–	–			–	7		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	–	–	0	11	4	2	3	1	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	1	0	–	–	–	0	–	–	–	0	–			0	21		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	1	2	4	8	6	1	2	3	1	4	2	4	2	2	1	2	0	5	3	1	1	2	1	1	2	1	1	1	1			4	69		3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	13	22	31	17	3	2	–	0	0	1	–	0	2	–	–	–	0	–	–	0	–	–	–	–	–	–	0	–	–	–	–			0	91		3
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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–			–	2		4
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	5	1	2	–	–	–	–	1	–	–	1	–	1	1	1	2	–	2	–	3	3	2	4	1	5	10	–	3	1	2	1			5	58		4
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	–		N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	5	31	51	37	5	9	9	4	6	8	5	11	18	9	5	9	3	4	2	6	1	1	1	5	4	6	11	8	8	16	6			–	304		4
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	1	2	1	–	–	–	–	–	–	–	–	1	–	1	1	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–			–	8		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	5	22	25	54	62	6	11	13	9	8	15	11	7	10	13	14	19	19	10	12	13	6	10	5	13	5	8	1	12	11	11	2			–	440		4
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	–		N/A
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	1	8	–	10	5	1	1	–	1	–	–	1	1	–	–	–	2	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–			–	32		4
51	LV	LV Line	LV OH Conductor	km	–	–	0	3	0	1	1	15	–	2	1	0	0	0	–	0	–	–	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	–			0	30		3
52	LV	LV Cable	LV UG Cable	km	1	–	9	46	72	110	65	12	15	21	3	10	6	9	4	7	6	3	5	2	1	1	2	3	4	2	2	0	1	1	1	2	1	0			2	427		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	2	0	1	14	4	22	88	19	3	1	0	0	3	1	1	2	1	1	1	0	2	1	0	1	0	0	0	0	1	0	1	1	0	–			3	171		3
54	LV	Connections	OH/UG consumer service connections	No.	–	1	114	2,208	3,946	3,559	5,427	40	53	60	195	256	277	196	233	117	99	92	97	82	57	63	67	84	62	53	66	70	116	91	129	145	75	36			–	18,146		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	3	31	30	1	4	–	–	2	–	–	–	–	–	–	–	–	–	–	1	22	5	–	2	5	13	10	–	–	1	–	–			–	130		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	1		4
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	–		N/A
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	1		4
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	–		N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–			–	–		N/A

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9 **9c: Overhead Lines and Underground Cables**

10

11 **Circuit length by operating voltage (at year end)**	Overhead (km)	Underground (km)	Total circuit length (km)
12 > 66kV	–	–	–
13 50kV & 66kV	–	–	–
14 33kV	1	27	28
15 SWER (all SWER voltages)	–	–	–
16 22kV (other than SWER)	–	–	–
17 6.6kV to 11kV (inclusive—other than SWER)	21	160	181
18 Low voltage (< 1kV)	30	427	456
19 **Total circuit length (for supply)**	52	614	666
20			
21 Dedicated street lighting circuit length (km)	25	146	171
22 Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–

23

24 **Overhead circuit length by terrain (at year end)**	Circuit length (km)	(% of total overhead length)
25 Urban	47	90%
26 Rural	2	3%
27 Remote only	–	–
28 Rugged only	2	4%
29 Remote and rugged	–	–
30 Unallocated overhead lines	2	3%
31 **Total overhead length**	52	100%

32

33	Circuit length (km)	(% of total circuit length)
34 Length of circuit within 10km of coastline or geothermal areas (where known)	51	8%

35

36	Total newly identified throughout the disclosure year	Total remaining at high risk at the disclosure year-end	
37 Number of overhead circuit sites at high risk from vegetation damage	8	9	*Not required before DY2026*

38

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

40 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	
41 [Single tree]	1	–	*Not required before DY2026*
42 [Single tree - Urban]	1	–	*Not required before DY2026*
43 [Single tree - Rural]	–	–	*Not required before DY2026*
44 [Row of trees]	7	–	*Not required before DY2026*
45 [Span between two poles (X metres)]	287 metres	0 metres	*Not required before DY2026*
46 [Other]	–	–	*Not required before DY2026*
47 **Total number of sites**	9	–	*Not required before DY2026*

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

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

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

** 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*

26

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

8 **9e(i): Consumer Connections and Decommissionings**

9 *Number of ICPs connected during year by consumer type*

	*Consumer types defined by EDB**	Number of connections (ICPs)
10		
11	Low user	16
12	Residential	71
13	General	35
14	Individual Half Hour	10
15		
16	**Connections total**	132

17 ** include additional rows if needed*

18

19 *Number of ICPs decommissioned during year by consumer type*

	*Consumer types defined by EDB**	Number of decommissionings
20		
21	Low user	2
22	Residential	20
23	General	29
24	Individual Non Half hour	1
25		
26	**Decommissionings total**	52

27 ** include additional rows if needed*

28

29 **Distributed generation**

30	Number of connections made in year	23	connections
31	Capacity of distributed generation installed in year	0.15	MVA

32

33 **9e(ii): System Demand**

34

35

			Demand at time of maximum coincident demand (MW)	
36		**Maximum coincident system demand**		
37		GXP demand	62	
38	*plus*	Distributed generation output at HV and above	–	
39		**Maximum coincident system demand**	62	
40	*less*	Net transfers to (from) other EDBs at HV and above	(1)	
41		**Demand on system for supply to consumers' connection points**	63	
42		**Electricity volumes carried**	**Energy (GWh)**	
43		Electricity supplied from GXPs	251	
44	*less*	Electricity exports to GXPs		
45	*plus*	Electricity supplied from distributed generation	1	
46	*less*	Net electricity supplied to (from) other EDBs	(13)	
47		**Electricity entering system for supply to consumers' connection points**	264	
48	*less*	Total energy delivered to ICPs	251	
49		**Electricity losses (loss ratio)**	13	4.8%
50				
51		**Load factor**	0.48	

52 **9e(iii): Transformer Capacity**

		(MVA)
53		
54	Distribution transformer capacity (EDB owned)	158
55	Distribution transformer capacity (Non-EDB owned)	2
56	**Total distribution transformer capacity**	160
57		
58		**(MVA)**
59	Zone substation transformer capacity (EDB owned)	187
60	Zone substation transformer capacity (Non-EDB owned)	–
61	**Total zone substation transformer capacity**	187

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 **10(i): Interruptions**

	Number of interruptions
Interruptions by class	
Class A (planned interruptions by Transpower)	–
Class B (planned interruptions on the network)	16
Class C (unplanned interruptions on the network)	27
Class D (unplanned interruptions by Transpower)	–
Class E (unplanned interruptions of EDB owned generation)	–
Class F (unplanned interruptions of generation owned by others)	–
Class G (unplanned interruptions caused by another disclosing entity)	5
Class H (planned interruptions caused by another disclosing entity)	–
Class I (interruptions caused by parties not included above)	–
Total	48

	≤3Hrs	>3hrs
Interruption restoration		
Class C interruptions restored within	16	11

	SAIFI	SAIDI
SAIFI and SAIDI by class		
Class A (planned interruptions by Transpower)	–	–
Class B (planned interruptions on the network)	0.0814	23.85
Class C (unplanned interruptions on the network)	0.4735	25.90
Class D (unplanned interruptions by Transpower)	–	–
Class E (unplanned interruptions of EDB owned generation)	–	–
Class F (unplanned interruptions of generation owned by others)	–	–
Class G (unplanned interruptions caused by another disclosing entity)	0.2481	60.67
Class H (planned interruptions caused by another disclosing entity)	–	–
Class I (interruptions caused by parties not included above)	–	–
Total	0.80	110.42

	SAIFI	SAIDI
Transitional SAIFI and SAIDI (previous method)		
Class B (planned interruptions on the network)	0.0814	23.85
Class C (unplanned interruptions on the network)	0.4204	25.90

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.***

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

	SAIFI	SAIDI
Cause		
Lightning	–	–
Vegetation	–	–
Adverse weather	0.0119	3.24
Adverse environment	–	–
Third party interference	–	–
Wildlife	0.0887	3.79
Human error	–	–
Defective equipment	0.2881	13.74
Other cause	0.0536	0.39
Unknown	0.0312	4.75

	SAIFI	SAIDI
Breakdown of third party interference		
Dig-in	–	–
Overhead contact	–	–
Vandalism	–	–
Vehicle damage	–	–
Other	–	–

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

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

	SAIFI	SAIDI
Main equipment involved		
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.0448	12.95
Distribution cables (excluding LV)	–	–
Distribution other (excluding LV)	0.0366	10.91

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

	SAIFI	SAIDI
Main equipment involved		
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.2645	15.01
Distribution cables (excluding LV)	0.2074	10.80
Distribution other (excluding LV)	0.0015	0.09

10(v): Fault Rate

	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Main equipment involved			
Subtransmission lines	–	1	–
Subtransmission cables	–	27	–
Subtransmission other	–		
Distribution lines (excluding LV)	12	21	57.01
Distribution cables (excluding LV)	9	160	5.63
Distribution other (excluding LV)	6		
Total	27		

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 **10(vi): Worst-performing feeders (unplanned)**

9

10 **SAIDI**

11

Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	BFE 1 - Bluff Borough	5.60	7	Defective Equipment	12.2	854	
2	SPY 8 - Spey St 8	4.62	1	Cause Unknown	6.1	534	
3	LEV 13 - Leven St 13	4.50	3	Adverse Weather	10.6	212	
4	RRD 8 - Racecourse Rd 8	2.76	2	Defective Equipment	6.0	943	

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

17

18 **SAIFI**

19

Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	BFE 1 - Bluff Borough	0.1415	7	Defective Equipment	12.2	854	
2	RRD 8 - Racecourse Rd 8	0.1063	2	Defective Equipment and Othe	6.0	943	
3	SOU 9 - Southern 9	0.0387	1	Defective Equipment	5.3	689	
4	LEV 11 - Leven St 11	0.0381	1	Wildlife	6.8	678	

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

25

26 **Customer Impact**

27

Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruptions	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	LEV 13 - Leven St 13	378	3	Adverse Weather	10.6	212	
2	BFE 2 - Ocean Beach	211	5	Defective Equipment	5.7	197	
3	SPY 8 - Spey St 8	154	1	Cause Unknown	6.1	534	
4	BFE 1 - Bluff Borough	117	7	Defective Equipment	12.2	854	

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

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2026

SCHEDULE 10a: REPORT ON INTERRUPTIONS

This schedule requires raw interruption data for the disclosure year. SAIDI and SAIFI is to be recorded using the multi-count approach.Where multiple feeders are affected, the interruption record is to be split into multiple interruptions, ie, one interruption record per feeder. 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 **10a(i): Raw interruption data**

8	Interruption identifi	Circuit location	Sub-network (where applicable)	Feeder(s) affected by interrupti	Start date (dd/mm/yyy	Start time (hh:mm:s	End date (dd/mm/yyy	End time (hh:mm:s	SAIDI valu	SAIFI valu	Number of ICPs interrupt	ICP interruption minut	Planned or unplanned interruption (Class B or C)	Cause	Any explanation to help clarify the context of the interruption, including what the cause is if recorded as 'Other cause'
9	97425-97425	992 The Big Oyster	ELIN	Bluff Borough BFE 1	2025/04/03	09:20	2025/04/03	11:21	0.123	0.0010	18	121	Planned	Planned interruption	Upgrade - Replace links
10	97463-97463	412/2 Bond S Of Victoria East	ELIN	Lev 13	2025/04/08	09:33	2025/04/08	11:48	0.364	0.0027	48	135	Unplanned	Wildlife	Bird strike - Broken wires
11	97463-97463	436 Mersey At Spey	ELIN	Lev 13	2025/04/08	09:33	2025/04/08	12:03	0.287	0.0019	34	150	Unplanned	Wildlife	Bird strike - Broken wires
12	97463-97463	449 Ettrick W. Of Mersey (449	ELIN	Lev 13	2025/04/08	09:33	2025/04/08	13:20	0.281	0.0012	22	227	Unplanned	Wildlife	Bird strike - Broken wires
13	97463-97463	Leven St 10	ELIN	Lev 10	2025/04/08	09:33	2025/04/08	10:05	0.358	0.0112	199	32	Unplanned	Wildlife	Bird strike - Broken wires
14	97463-97463	Leven St 11	ELIN	Lev 11	2025/04/08	09:33	2025/04/08	10:05	1.224	0.0382	680	32	Unplanned	Wildlife	Bird strike - Broken wires
15	97463-97463	Leven St 12	ELIN	Lev 12	2025/04/08	09:33	2025/04/08	10:05	1.006	0.0314	559	32	Unplanned	Wildlife	Bird strike - Broken wires
16	97463-97463	492 Reserve W Of Bond (492)	ELIN	Lev 13	2025/04/08	09:33	2025/04/08	10:14	0.012	0.0003	5	41	Unplanned	Wildlife	Bird strike - Broken wires
17	97463-97463	162/2 Victoria Ave At Prison (2	ELIN	Lev 13	2025/04/08	09:33	2025/04/08	11:42	0.080	0.0006	11	129	Unplanned	Wildlife	Bird strike - Broken wires
18	97463-97463	410 Mersey N Of Bute	ELIN	Lev 13	2025/04/08	09:33	2025/04/08	12:15	0.173	0.0011	19	162	Unplanned	Wildlife	Bird strike - Broken wires
19	97726-97726	304/4 Conway/Trent Reserve	ELIN	Racecourse Rd 8 RRD 8	2025/05/14	11:36	2025/05/14	11:42	0.035	0.0058	104	6	Unplanned	Other cause	Overload - Blown fuse
20	97726-97726	Racecourse Rd 8	ELIN	Racecourse Rd 8 RRD 8	2025/05/14	11:36	2025/05/14	11:39	0.072	0.0241	428	3	Unplanned	Other cause	Overload - Blown fuse
21	97726-97726	322/1 Lithgow N Of Lithgow Pl	ELIN	Racecourse Rd 8 RRD 8	2025/05/14	11:36	2025/05/14	11:42	0.139	0.0232	413	6	Unplanned	Other cause	Overload - Blown fuse
22	97804-97804	Shannon St S Of Gore St	ELIN	Bluff Borough BFE 1	2025/05/26	09:02	2025/05/26	12:45	2.509	0.0112	200	223	Planned	Planned interruption	Upgrade - Replace wire
23	97869-97869	412/2 Bond S Of Victoria East	ELIN	Leven St 13 LEV 13	2025/05/31	03:27	2025/05/31	07:59	0.400	0.0018	32	272	Unplanned	Adverse weather	High winds - Failed insulator
24	97869-97869	436 Mersey At Spey	ELIN	Leven St 13 LEV 13	2025/05/31	03:27	2025/05/31	08:06	1.177	0.0042	75	279	Unplanned	Adverse weather	High winds - Failed insulator
25	97869-97869	404 Bond Pl. W. Of Mersey (40	ELIN	Leven St 13 LEV 13	2025/05/31	03:27	2025/05/31	12:24	0.513	0.0010	17	537	Unplanned	Adverse weather	High winds - Failed insulator
26	97869-97869	Leven St 13	ELIN	Leven St 13 LEV 13	2025/05/31	03:27	2025/05/31	07:13	1.055	0.0047	83	226	Unplanned	Adverse weather	High winds - Failed insulator
27	97869-97869	489/2 Airport Ave N Of Stead	ELIN	Leven St 13 LEV 13	2025/05/31	03:27	2025/05/31	03:41	0.004	0.0003	5	14	Unplanned	Adverse weather	High winds - Failed insulator
28	97927-97927	974 Barrow E. Of Palmer (974	ELIN	Ocean Beach BFE 2	2025/06/03	13:08	2025/06/03	15:03	0.162	0.0014	25	115	Unplanned	Defective equipment	Deterioration - Damaged wire
29	98214-98214	624/1 Ure S Of Bourke	ELIN	Racecourse Rd 9 RRD 9	2025/07/08	08:31	2025/07/08	15:02	1.847	0.0047	84	391	Planned	Planned interruption	Upgrade - Replace transformer
30	98265-98265	718/3 Earn W Of Princess	ELIN	Southern 7 SOU 7	2025/07/15	11:00	2025/07/15	15:50	1.272	0.0044	78	290	Planned	Planned interruption	Upgrade - RMU 718 maintenance
31	98344-98344	Foyle W. Of Palmer	ELIN	Bfe 1 (Bnn)	2025/07/25	02:09	2025/07/25	03:21	1.462	0.0203	361	72	Unplanned	Defective equipment	Deterioration - Failed lead
32	98344-98344	Gore St Cb	ELIN	Bfe 2 (Grs)	2025/07/25	02:09	2025/07/25	03:21	0.344	0.0048	85	72	Unplanned	Defective equipment	Deterioration - Failed lead
33	98344-98344	Bann St Cb Bann St Cb	ELIN	Bfe 1 (Bnn)	2025/07/25	02:09	2025/07/25	02:56	0.019	0.0004	7	47	Unplanned	Defective equipment	Deterioration - Failed lead
34	98344-98344	Ocean Beach	ELIN	Bfe 2	2025/07/25	02:09	2025/07/25	03:09	0.003	0.0001	1	60	Unplanned	Defective equipment	Deterioration - Failed lead
35	98344-98344	995 Gore E Of Shannon	ELIN	Bfe 2	2025/07/25	02:09	2025/07/25	05:34	1.268	0.0062	110	205	Unplanned	Defective equipment	Deterioration - Failed lead
36	98355-98355	Bluff Borough	ELIN	Bluff Borough BFE 1	2025/07/26	09:31	2025/07/26	12:20	0.333	0.0020	35	169	Unplanned	Defective equipment	Deterioration - Replace switch
37	98355-98355	Bann St Cb Bann St Cb	ELIN	Bluff Borough BFE 1	2025/07/26	12:15	2025/07/26	12:20	0.094	0.0187	333	5	Unplanned	Defective equipment	Deterioration - Replace switch
38	98624-98624	Leven St 9	ELIN	Leven St 9 LEV 9	2025/08/28	11:23	2025/08/28	12:00	0.004	0.0001	2	37	Unplanned	Defective equipment	Deterioration - Failed cable
39	98624-98624	Do 15845	ELIN	Leven St 9 LEV 9	2025/08/28	11:23	2025/08/30	13:25	0.169	0.0001	1	3002	Unplanned	Defective equipment	Deterioration - Failed cable
40	98620-98620	621/1 Fern S Of Talbot	ELIN	Racecourse Rd 12 RRD 12	2025/09/02	09:04	2025/09/02	14:48	2.361	0.0069	122	344	Planned	Planned interruption	Upgrade - RMU maintenance
41	98617-98617	177/3 Winter Gardens (3)	ELIN	Spey St 7 SPY 7	2025/09/02	10:09	2025/09/02	13:30	0.023	0.0001	2	201	Unplanned	Unknown	Deterioration - Failed fuses (lv)
42	98719-98719	118/2 Kelvin S Of Herbert (2)	ELIN	Spey St 6 SPY 6	2025/09/08	08:47	2025/09/08	13:54	0.777	0.0025	45	307	Planned	Planned interruption	Maintenance - RMU Maintenance
43	98719-98719	118/5 Kelvin S Of Herbert (5)	ELIN	Spey St 6 SPY 6	2025/09/08	08:47	2025/09/08	13:57	0.820	0.0026	47	310	Planned	Planned interruption	Maintenance - RMU Maintenance
44	99017-99017	431/1 Sth Construction Co Ro	ELIN	Leven St 9 LEV 9	2025/09/28	08:00	2025/09/28	10:58	0.030	0.0002	3	178	Planned	Planned interruption	Upgrade - RMU maintenance
45	99024-99024	Southern 8	ELIN	Southern 8 SOU 8	2025/09/29	08:24	2025/09/29	10:37	0.007	0.0001	1	133	Unplanned	Other cause	Upgrade - Decommision transformer
46	99080-99080	962 Bann E Of Liffey 962	ELIN	Bluff Borough BFE 1	2025/10/03	09:32	2025/10/03	13:40	1.702	0.0069	122	248	Planned	Planned interruption	Upgrade - CB maintenance
47	99143-99143	Do 16025	ELIN	Ocean Beach BFE 2	2025/10/09	08:45	2025/10/09	09:52	0.011	0.0002	3	67	Planned	Planned interruption	Upgrade - Replace transformer
48	99189-99189	Do 14529	ELIN	Bluff Borough BFE 1	2025/10/11	14:16	2025/10/11	15:54	0.099	0.0010	18	98	Unplanned	Unknown	Unknown - Blown fuses
49	99219-99219	361/1 Mitchell W Of Lindisfar	ELIN	Spey St 5 SPY 5	2025/10/14	08:30	2025/10/14	13:10	2.740	0.0098	174	280	Planned	Planned interruption	Upgrade - RMU maintenance
50	99226-99226	335/1 Racecourse Rd. Carnaw	ELIN	Racecourse Rd 8 RRD 8	2025/10/15	12:43	2025/10/15	14:07	0.496	0.0059	105	84	Unplanned	Defective equipment	Deterioration - Failed cable
51	99226-99226	304/2 Conway/Trent Reserve	ELIN	Racecourse Rd 8 RRD 8	2025/10/15	12:43	2025/10/15	13:44	0.542	0.0089	158	61	Unplanned	Defective equipment	Deterioration - Failed cable
52	99226-99226	304/3 Conway/Trent Reserve	ELIN	Racecourse Rd 8 RRD 8	2025/10/15	12:43	2025/10/15	14:23	0.377	0.0038	67	100	Unplanned	Defective equipment	Deterioration - Failed cable
53	99226-99226	Racecourse Rd 8	ELIN	Racecourse Rd 8 RRD 8	2025/10/15	12:43	2025/10/15	13:23	0.817	0.0204	363	40	Unplanned	Defective equipment	Deterioration - Failed cable
54	99226-99226	371/4 Tay W Of Stuart (4)	ELIN	Racecourse Rd 8 RRD 8	2025/10/15	12:43	2025/10/15	13:03	0.283	0.0142	252	20	Unplanned	Defective equipment	Deterioration - Failed cable
55	99236-99236	Do 128652	ELIN	Bluff Borough BFE 1	2025/10/16	08:30	2025/10/16	09:03	0.013	0.0004	7	33	Unplanned	Defective equipment	Deterioration - Blown fuse
56	99447-99447	Spey St 14	ELIN	Spey St 14 SPY 14	2025/10/30	08:03	2025/10/31	17:18	0.112	0.0001	1	1995	Unplanned	Defective equipment	Faulty U/G cable - Defective equipment
57	99514-99514	Spey St 14	ELIN	Spey St 14 SPY 14	2025/11/05	18:30	2025/11/05	23:05	0.031	0.0001	2	275	Unplanned	Other cause	Upgrade - New RMU installation
58	99583-99583	Bann St Cb Bann St Cb	ELIN	Bfe 1 (Bnn)	2025/11/08	15:29	2025/11/08	16:20	1.050	0.0206	366	51	Unplanned	Defective equipment	Deterioration - Failed connection
59	99583-99583	Bluff Borough	ELIN	Bfe 1	2025/11/08	15:29	2025/11/08	16:18	1.553	0.0276	491	49	Unplanned	Defective equipment	Deterioration - Failed connection
60	99583-99583	Gore St Cb	ELIN	Bfe 2 (Grs)	2025/11/08	15:29	2025/11/08	16:16	0.124	0.0026	47	47	Unplanned	Defective equipment	Deterioration - Failed connection
61	99583-99583	974 Barrow E. Of Palmer (974	ELIN	Bfe 2 (Grs)	2025/11/08	15:29	2025/11/08	16:31	0.067	0.0014	25	62	Unplanned	Defective equipment	Deterioration - Failed connection
62	99583-99583	Do 620119	ELIN	Bfe 2 (Grs)	2025/11/08	15:29	2025/11/08	19:19	0.194	0.0008	15	230	Unplanned	Defective equipment	Deterioration - Failed connection
63	99583-99583	Gore St Cb	ELIN	Bfe 2 (Grs)	2025/11/08	16:48	2025/11/08	19:19	0.008	0.0001	1	151	Unplanned	Defective equipment	Deterioration - Failed connection
64	99583-99583	912/2 Big Glory (2)	ELIN	Bfe 2 (Grs)	2025/11/08	16:48	2025/11/08	17:08	0.001	0.0001	1	20	Unplanned	Defective equipment	Deterioration - Failed connection
65	99583-99583	Bluff Borough	ELIN	Bfe 1	2025/11/08	16:48	2025/11/08	17:08	0.552	0.0276	491	20	Unplanned	Defective equipment	Deterioration - Failed connection
66	99583-99583	Bann St Cb Bann St Cb	ELIN	Bfe 1 (Bnn)	2025/11/08	16:48	2025/11/08	17:14	0.535	0.0206	366	26	Unplanned	Defective equipment	Deterioration - Failed connection
67	99583-99583	973 Foreshore Rd	ELIN	Bfe 2 (Grs)	2025/11/08	16:48	2025/11/08	17:14	0.102	0.0039	70	26	Unplanned	Defective equipment	Deterioration - Failed connection
68	99583-99583	Do 620119	ELIN	Bfe 2 (Grs)	2025/11/08	19:36	2025/11/08	19:39	0.003	0.0008	15	3	Unplanned	Defective equipment	Deterioration - Failed connection
69	100053-100053	814/3 Lime S Of Tweed (3)	ELIN	Southern 9 SOU 9	2025/11/23	04:27	2025/11/23	08:20	0.747	0.0032	57	233	Unplanned	Defective equipment	Deterioration - Failed cable
70	100053-100053	Southern 9	ELIN	Southern 9 SOU 9	2025/11/23	04:27	2025/11/23	05:01	1.207	0.0355	631	34	Unplanned	Defective equipment	Deterioration - Failed cable
71	100382-100382	Spey St 8	ELIN	Spey St 8 SPY 8	2025/12/06	22:31	2025/12/07	01:05	4.617	0.0300	533	154	Unplanned	Unknown	Unknown - CB trip
72	100551-100551	Leven St 13	ELIN	Leven St 13 LEV 13	2025/12/14	06:30	2025/12/14	11:45	0.035	0.0001	2	315	Unplanned	Other cause	Upgrade - Replace transformer
73	100607-100607	Gore St (5)	ELIN	Bluff Borough BFE 1	2025/12/16	09:00	2025/12/16	14:29	3.701	0.0112	200	329	Planned	Planned interruption	Upgrade - Replace Poles
74	100650-100650	491 491 Cobbe S Of Stead	ELIN	Leven St 13 LEV 13	2025/12/17	09:28	2025/12/17	15:59	0.066	0.0002	3	391	Unplanned	Other cause	Upgrade - Replace transformer
75	100660-100660	Gore St Cb	ELIN	Ocean Beach BFE 2	2025/12/18	14:31	2025/12/18	15:12	0.039	0.0010	17	41	Unplanned	Defective equipment	Failed tie wire - Wire off insulator
76	100691-100691	745/3 Martin At Nelson (3)	ELIN	Southern 10 SOU 10	2025/12/22	07:17	2025/12/22	08:30	0.140	0.0019	34	73	Unplanned	Defective equipment	Deterioration - Failed cable "UQ"
77	100691-100691	745/3 Martin At Nelson (3)	ELIN	Southern 10 SOU 10	2025/12/22	07:17	2025/12/22	08:48	0.169	0.0019	33	91	Unplanned	Defective equipment	Deterioration - Failed cable "UQ"
78	100691-100691	745/3 Martin At Nelson (3)	ELIN	Southern 10 SOU 10	2025/12/22	07:17	2025/12/22	09:03	0.143	0.0013	24	106	Unplanned	Defective equipment	Deterioration - Failed cable "UQ"
79	100842-100842	859/4 Freshbake Baker St (Cb	ELIN	Racecourse Rd 6 RRD 6	2026/01/05	15:24	2026/01/05	17:45	0.008	0.0001	1	141	Unplanned	Unknown	Unknown - Fire
80	100946-100946	260/3 Ness S Of Tyne(3)	ELIN	Spey St 14 SPY 14	2026/01/13	21:30	2026/01/13	23:24	0.032	0.0003	5	114	Planned	Planned interruption	Routine service - RMU maintenance
81	101000-101000	961 Bann W Of Liffey	ELIN	Bluff Borough BFE 1	2026/01/20	10:00	2026/01/20	12:21	0.785	0.0056	99	141	Planned	Planned interruption	Upgrade - Replace switch
82	101007-101007	350/3 At Bill Mary	ELIN	Spey St 5 SPY 5	2026/01/20	10:00	2026/01/20	14:16	0.950	0.0037	66	256	Planned	Planned interruption	Routine service - Transformer testing
83	101211-101211	548/1 Jed N Of Yarrow	ELIN	Spey St 12 SPY 12	2026/02/07	21:25	2026/02/07	22:08	0.201	0.0047	83	43	Unplanned	Defective equipment	Deterioration - Cable failure
84	101211-101211	585/1 Deveron N Of Don	ELIN	Spey St 12 SPY 12	2026/02/07	21:25	2026/02/07	22:32	0.015	0.0002	4	67	Unplanned	Defective equipment	Deterioration - Cable failure
85	101211-101211	519/1 Deveron S Of Spey (1)	ELIN	Spey St 12 SPY 12	2026/02/07	21:25	2026/02/07	21:38	0.091	0.0070	125	13	Unplanned	Defective equipment	Deterioration - Cable failure
86	101211-101211	Spey St 12	ELIN	Spey St 12 SPY 12	2026/02/07	21:25	2026/02/07	22:28	0.241	0.0038	68	63	Unplanned	Defective equipment	Deterioration - Cable failure
87	101211-101212	Leven St 10	ELIN	Leven St 10 LEV 10	2026/02/07	21:25	2026/02/07	21:38	0.146	0.0112	200	13	Unplanned	Defective equipment	Deterioration - Cable failure
88	101215-101215	Ocean Beach	ELIN	Ocean Beach BFE 2	2026/02/09	12:03	2026/02/09	12:56	0.069	0.0013	23	53	Unplanned	Defective equipment	Deterioration - Repair leads
89	101250-101250	Do 37382	ELIN	Leven St 9 LEV 9	2026/02/13	10:37	2026/02/13	11:11	0.004	0.0001	2	34	Unplanned	Defective equipment	Defective equipment - Broken conductor
90	101269-101269	819/5 Tweed @ Inglewood (5)	ELIN	Southern 8 SOU 8	2026/02/15	07:00	2026/02/15	13:43	2.222	0.0052	98	403	Planned	Planned interruption	Routine maintenance - RMU service
91	101453-101453	Do 14529	ELIN	Bluff Borough BFE 1	2026/03/05	23:32	2026/03/05	23:53	0.021	0.0010	18	21	Unplanned	Defective equipment	Deterioration - Failed connection
92	101538-101538	485/1 Victoria Ave E Of Mersi	ELIN	Leven St 13 LEV 13	2026/03/15	07:00	2026/03/15	14:02	1.970	0.0047	83	422	Planned	Planned interruption	Maintenance - Maintenance
93	101609-101609	Ocean Beach	ELIN	Ocean Beach BFE 2	2026/03/24	10:45	2026/03/24	11:38	0.003	0.0001	1	53	Unplanned	Defective equipment	Deterioration - Lead off

[1] *Extend table as necessary to disclose information for all individual interruptions*

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2026**

SCHEDULE 11c: REPORT ON CYBERSECURITY EXPENDITURE FORECAST

This schedule requires details on the cybersecurity expenditure for various categories.

sch ref

23 **11c Expenditure Forecast** **$000 (in constant prices)**

24

25	**Capex Forecast**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
26	Cybersecurity (Commission only)	-	-	-	-	-	-	-	-	-	-	-
27												
28	**Opex Forecast**											
29	Cybersecurity (Commission only)	46	10	10	10	10	10	10	10	10	10	10
30												
31												
32												

SCHEDULE 14 MANDATORY EXPLANATORY NOTES

(Guidance Note: This Microsoft Word version of Schedules 14, 14a and 15 is from the Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018. 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).

Box 1: Explanatory comment on return on investment

Electricity Invercargill Limited (EIL) achieved a post-tax ROI of 7.16% which is above the 75th percentile estimate of post-tax WACC of 6.62%. EIL also achieved a 7.80% vanilla ROI which is above the 75th percentile estimate of vanilla WACC of 7.26%.

No items were reclassified.

Regulatory Profit (Schedule 3)

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

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

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

Box 2: Explanatory comment on regulatory profit

Other regulated income of $94k is for line charges to another lines company for the use of a circuit breaker and feeder to supply some customers from an EIL substation.

No items were reclassified in the disclosure year.

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

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

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

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

Box 3: Explanatory comment on merger and acquisition expenditure
There were no merger or acquisition expenses incurred in the disclosure year.

Value of the Regulatory Asset Base (Schedule 4)

7. In the box below, comment on the value of the regulatory asset base (rolled forward) in Schedule 4. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)
The calculation of the Regulatory Asset Base (RAB) was stated using the 31 March 2025 closing figure of $119,114k as a starting point with inflationary indexing over the year to 31 March 2026, plus additions less disposals. This resulted in a closing RAB balance of $124,346k.

No items were reclassified.

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
The expenditure deductible but not in regulatory profit is the $6k cost of easements which is a tax deductible expense.

There are no other permanent differences.

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)

Taxable Capital Contributions:	$	345
	$	345
Tax Rate:		28%
Temporary Differences	$	97

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

With the exception of some Business support costs (which have been apportioned using the ABAA method via a revenue proxy cost allocator), all other costs incurred by Electricity Invercargill Limited are directly attributable to electricity distribution business.

A proxy cost allocator is used as there is no direct relationship between not directly attributable business support costs and how they have been incurred.
No items were reclassified.

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

All network assets are directly attributable.

No items were reclassified.

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

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

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

Box 9: Explanation of capital expenditure for the disclosure year

The materiality threshold applied to identify programmes or projects during the disclosure year was $100k. Lower value projects with defined scope were included in the list for specific identification within categories.

No items were reclassified during the disclosure year.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

    13.3 Commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, a including the value of the expenditure the purpose of the expenditure, and the operational expenditure categories the expenditure relates to.

Box 10: Explanation of operational expenditure for the disclosure year

No items were reclassified during the disclosure year.

There have been no material items of atypical expenditure during the year and disclosed in Schedule 6b.

Variance between forecast and actual expenditure (Schedule 7)

14. In the box below, comment on variance in actual to forecast expenditure for the disclosure year, as reported in Schedule 7. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 11: Explanatory comment on variance in actual to forecast expenditure

No items were reclassified during the disclosure year. Refer to each classification under point 12 and 13 above.

Capital Expenditure:
The actual expenditure on network assets was 4% below budget.

Consumer connection:

- Actual consumer connection expenditure was broadly in line with budget.

Asset replacement and renewal:

- Actual expenditure was 7% below budget as a result of project timing and delivery phasing. The replacement and renewal programme remained on track and no material impact on network reliability, asset condition, or network risk.

Asset Relocations:

- The overspend was due to higher-than-expected customer demand for relocation works. As this expenditure is customer-driven, actual expenditure can vary from budget depending on the timing and volume of customer requests.

Quality of Supply:

- 83% below target primarily due to the rescheduling of certain projects into future years.

Reliability, Safety and Environment:

- 24% overspend due to the accelerated delivery of planned works during the disclosure year. The additional investment enhanced network resilience, improved public and staff safety, and reduced long-term network and operational risks.

Box 11: Explanatory comment on variance in actual to forecast expenditure (continuation)

Operational Expenditure:

The actual operational expenditure was 9% below budget.

Service interruptions and emergencies:

- 40% overspend due to higher levels of reactive response activity during the year, including storm restoration works and cable fault responses.

Vegetation management:

- Actual expenditure exceeded forecast primarily due to unplanned tree felling works. Given the relatively small budget for this category, the additional work resulted in a significant percentage variance.

Routine and corrective maintenance and inspection:

- 16% underspend due to fewer defects identified than anticipated from the inspection programme.

Asset replacement and renewal:

- Most renewal activities were delivered through the capital programme resulting to a nil expenditure in this category.

Non-network opex:

System operations and network support

- 16% underspent primarily due to the decision not to proceed with a captive insurance arrangement.

Business support

- 3% underspent primarily due to minor expenditure adjustments made during the year that were not reflected in the target.

Information relating to revenues and quantities for the disclosure year

15. In the box below provide-

15.1 a comparison of the target revenue disclosed before the start of the disclosure year, in accordance with clause 2.4.1 and subclause 2.4.3(3) to total billed line charge revenue for the disclosure year, as disclosed in Schedule 8; and

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

Box 12: Explanatory comment relating to revenue for the disclosure year

Target revenue for the year was $23,676k. The total billed revenue for the year was $23,360k, which is $316k below.

The variance was primarily driven by lower-than-anticipated winter demand associated with unseasonably warm weather conditions, which reduced line charge revenue making it slightly lower (1% variation) than the targeted result.

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 13: Commentary on network reliability for the disclosure year

Electricity Invercargill Limited (EIL) has calculated and disclosed SAIDI and SAIFI metrics consistent with the 2012 Electricity Distribution Business (EDB) ID Determination, incorporating all amendments up to 2 June 2026.

SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) are consumer-focused measures of average outage duration and frequency. SAIDI is calculated using the duration of each interruption stage and the number of consumers affected. SAIFI is calculated using the 'multi-count' methodology, which counts successive interruptions within a main outage.

Up until the 2024 disclosure year, EIL did not include successive interruptions after the initial interruption when calculating SAIFI. For continuity, this calculation method is recorded in Schedule 10, reference rows 39-41 (Transitional SAIFI and SAIDI – previous method). The transitional SAIFI figure should be used to compare to historic disclosures to those from disclosure year 2024 onwards.

Class C (unplanned) interruption SAIDI increased by 23%, from 21.00 to 25.90 minutes, while Class B (planned) SAIDI decreased by 7%, from 25.75 to 23.85 minutes. The total number of Class C interruptions increased slightly from 25 to 27, while Class B interruptions decreased from 30 to 16. The number of interruptions exceeding 3 hours' duration was unchanged at 11.

Class C SAIFI, at 0.4735, was the major contributor (59%) to the total SAIFI figure. The most significant cause of Class C interruptions was defective equipment, which increased compared to the previous year in both SAIDI (+26%) and SAIFI (+64%).

Class G interruptions (caused by another disclosing entity) contributed 60.67 minutes to total SAIDI, the largest single component this year. During the 23 October windstorm, a prolonged outage affected Bluff for approximately 10 hours due to a failure on the upstream network operated by The Power Company Limited.

Only 11% of EIL's high voltage network consists of overhead distribution lines, yet 54% of planned interruptions and 58% of unplanned interruptions, based on the SAIDI impact, occurred on these lines. The fault rate for distribution lines per 100 km improved from 61.76 to 57.01, while distribution cable faults increased from 3.13 to 5.63. No faults occurred on the subtransmission lines or cables.

Due to the small footprint and underground nature of the EIL network, the probability of an interruption is low. However, in the event of an interruption, the number of customers affected tends to be high as a percentage of the total customer base, making SAIDI and SAIFI difficult to predict in any given year.

Insurance cover

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

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

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

Box 14: Explanation of insurance cover

Electricity Invercargill Limited insures its substations, network equipment and buildings.

- Substations and network equipment are insured for $40.9 million.

Lines and cables are not insured. Electricity Invercargill Limited therefore "self-insures" its lines and cables but does not recognise the cost of self-insurance.

Amendments to previously disclosed information

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

    18.1 a description of each error; and

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

Box 15: Disclosure of amendment to previously disclosed information

No amendments were disclosed.

SCHEDULE 14A MANDATORY EXPLANATORY NOTES ON FORECAST

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

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

20. 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)

21. 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
Inflationary assumptions were used to calculate the nominal prices in the forecast.

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

22. 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
Nominal Prices are based on publicly available New Zealand Treasury's economic forecast indicated in the Half Year Economic Fiscal Update (HYEFU) report released in December 2024:

	2026	2027	2028	2029	2030
Inflator (CAPEX & OPEX)	2.1%	2.0%	2.0%	2.0%	2.0%

Forecasts are in line with the business plan projections and explanations outlined in the Asset Management Plan.

Schedule 15 Voluntary Explanatory Notes

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

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

    23.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1 and 2.5.2;

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

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.

24. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Schedule 5b

Electricity Invercargill Limited disposed of its entire shareholding in subsidiary Pylon Limited in the prior disclosure year. As part of that transaction, Electricity Invercargill Limited also disposed of its interests in PowerNet Limited, the OtagoNet Joint Venture, and Lakeland Network Limited. As a result of this change in ownership structure, no related party transactions requiring disclosure under Schedule 5b have been identified for the current disclosure year for the above entities.

Schedule 10

Network reliability meets the quality requirements under DPP4. However, because the outage reporting process is manual, EIL faces inherent limitations in its ability to collect and record the network reliability information required to be disclosed under Schedule 10(i) to 10(iv). As a result, no independent evidence is available to confirm the completeness and accuracy of recorded faults, and control over the completeness and accuracy of the interconnection point ('ICP') data used in the SAIDI and SAIFI calculations was limited throughout the year.

Several actions and initiatives are underway to address these limitations, including the increased use of smart meter data; strengthened processes for recording and confirming outages from the outage system; and improved retention of documentation.

Over the medium term, EIL's network manager PowerNet has commenced a project to develop and implement an Advanced Distribution Management System (ADMS), which will integrate SCADA, outage management, and operational decision support into a single platform. The project is currently in the business-case phase and is expected to take several years to fully implement.

Schedule 11c

Cybersecurity expenditure is undertaken by PowerNet Limited as part of shared facility costs associated with system operations and network support. In accordance with the Network Management Agreement, these costs are allocated to Electricity Invercargill Limited through established charging arrangements.

4. APPENDIX - Related Party Transaction: Additional Information Disclosure

4.1 INTRODUCTION

For the purpose of meeting the 2026 Related Party Transaction reporting requirements, in accordance with section 2.3.6 of the Electricity Distribution Information Disclosure (Related Party Transaction Threshold Amendment Determination 2026 (19 February 2026).

The disclosure is intended to identify the existence and extent of related party transactions, explain what the transactions relate to, and describe the basis on which Electricity Invercargill Limited (EIL) considers the pricing to be consistent with an equivalent arm's-length transaction and supported by objectively verifiable information.

The following information is provided in reference to and support of:

- **Electricity Invercargill Limited's 2026 Information Disclosure**, for the year ended 31 March 2026 - Schedule 5(b) Related Party Transactions

4.2 INFORMATION DISCLOSURE REQUIREMENTS

The Related Party Transaction information disclosed on the following pages has been prepared in accordance with **Limited Disclosure** requirements, due to the level of expenditure incurred by EIL being less than $30 million, for the year ended 31 March 2026.

Limited Disclosure requires additional information be provided associated with related party transactions, limited to details of related party relationships and nature of work undertaken.

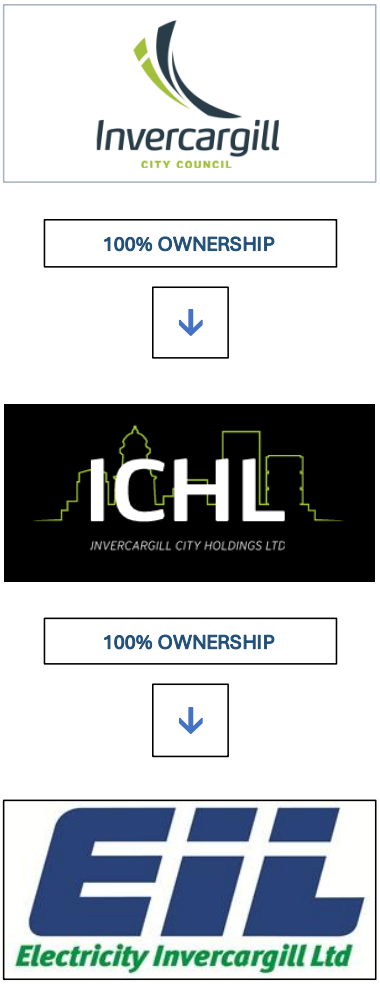
This information is also subject to the Information Disclosure assurance opinion and Director Certification.

4.3 RELATED PARTY RELATIONSHIPS

EIL disposed of its interests in PowerNet Limited, the OtagoNet Joint Venture and Lakeland Network Limited on 29 November 2024. Accordingly, above mentioned entities were not a related party of EIL during the disclosure year ended 31 March 2026.

Company Structure

Electricity Invercargill Limited (EIL) is wholly-owned by the Invercargill City Council (ICC) through its subsidiary company, Invercargill City Holdings Limited (ICHL). The following diagram illustrates EIL's direct ownership hierarchy for information disclosure reporting.



Related Parties and Nature of Services

Related Party	Relationship	Nature of Transaction	Amount ($000)	Schedule 5b
ICHL	Immediate Parent Entity	Governance and management support; funding and treasury services, including costs charged under applicable group arrangements.	157	Business support
ICC	Ultimate Controlling Shareholder	Local authority services applicable to EIL, principally network rates.	204	Other related party transactions
ICC	Ultimate Controlling Shareholder	Customer contribution towards new connection projects	7	Value of capital contributions
Directors	Members of the Board	Responsible for governance and oversight of EIL	198	Business support

Arm's Length Requirement

EIL considers that the related party transactions disclosed for the year ended 31 March 2026 were conducted on terms consistent with an equivalent arm's-length transaction. This conclusion is based on the following controls and evidence:

- **Defined scope and authority:** The nature of services, responsibilities and charging arrangements are documented through applicable agreements, approved arrangements, invoices, rates assessments and supporting records.
- **Objective pricing inputs:** Charges are based on identifiable cost drivers, external borrowing or facility costs where relevant, approved fee arrangements, statutory or council-set rates, and other records capable of independent verification.
- **No preferential treatment:** EIL applies the same governance, approval and payment controls to related party expenditure as it applies to comparable third-party expenditure. Related party status does not remove the requirement for appropriate review and authorisation.
- **Commercial reasonableness:** Management assesses whether the nature and amount of each charge are reasonable having regard to the service received, available market information or benchmarks where practicable, and the underlying supporting documentation.
- **Governance and assurance:** Related party transactions are separately identified for Schedule 5b, reviewed as part of the Information Disclosure preparation process, included within the scope of Director certification, and subject to the applicable assurance requirements.

The Audit Office
Te Mana Arotake

Independent Assurance Report

To the directors of Electricity Invercargill Limited and to the Commerce Commission on the disclosure information for the disclosure year ended 31 March 2026 as required by the Electricity Distribution Information Disclosure (Amendments related to IM Review 2023) Amendment Determination 2024 [2024] NZCC 31 (as amended)

Electricity Invercargill Limited (the company) is required to disclose certain information under the Electricity Distribution Information Disclosure (Amendments related to IM Review 2023) Amendment Determination 2024 [2024] NZCC 31 (as amended) (the Determination) and to procure an assurance report by an independent auditor in terms of section 2.8.1 of the Determination.

The Auditor-General is the auditor of the company.

The Auditor-General has appointed me, Elizabeth Adriana (Adri) Smit, using the staff and resources of PricewaterhouseCoopers, to undertake a reasonable assurance engagement, on his behalf, on whether the information prepared by the company for the disclosure year ended 31 March 2026 (the Disclosure Information) complies, in all material respects, with the Determination.

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

- Schedules 1, 2, 3, 3a, 4, 5a to 5h, 6a and 6b (except for information required to be disclosed in Schedule 6(b)(i) under the "Vegetation-related" and "Other" sub-categories of the "Service interruptions and emergencies" category, and the "assessment and notification costs", "Felling or trimming vegetation – in-zone", "Felling or trimming vegetation – out-of-zone", and "Other" sub-categories of the "Vegetation management" category), 7, 10 and 10a (limited to the SAIDI and SAIFI information) and 14 (limited to the explanatory notes in boxes 1 to 11) of the Determination.

- The basis for the valuation of related party transactions (the Related Party Transaction Information) in accordance with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Electricity Distribution Services Input Methodologies Determination 2012 (as amended) (the IM Determination); and the information disclosed under clauses 2.3.8, 2.3.10 to 2.3.12.

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, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the company;
- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records, sourced from the company's financial and non-financial systems;
- the Disclosure Information complies, 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 1 of Schedule 15, there are inherent limitations in the ability of the Company to collect and record the network reliability information specifically the interconnection points ('ICP's') affected by an interruption and the duration of the interruption used in calculating the amounts required to be disclosed in the Schedules 10(i) to 10(vi) and 10a. Consequently, there is no independent evidence available to support the completeness and accuracy of recorded faults, and control over the completeness and accuracy of interconnection point ('ICP') data included in the SAIDI and SAIFI calculations was limited throughout the year.

There are no practical audit procedures that we could adopt to independently confirm that all the faults and ICP data were properly recorded for the purposes of inclusion in the amounts relating to quality measures set out in Schedules 10(i) to 10(vi) and 10a.

Because of the potential effect of these limitations, we are unable to obtain sufficient appropriate audit evidence to confirm the completeness and accuracy of the data that forms the basis of the compilation of Schedules 10(i) to 10(vi) and 10a.

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

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

Key Assurance Matters

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

Key Assurance Matter	How our procedures addressed the key assurance matter
Regulatory Asset Base 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 reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions in the underlying accounting records 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 underlying financial records; • We have performed a reasonableness test to ensure the regulatory depreciation expense is calculated in line 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.

Directors' responsibilities

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

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

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

Auditor's responsibilities

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

- as far as appears from an examination, the information used in the preparation of the audited Disclosure Information has been properly extracted from the company's accounting and other records, sourced from its financial and non-financial systems;
- as far as appears from an examination, proper records to enable the complete and accurate compilation of the audited Disclosure Information required by the Determination have been kept by the company and, if not, the records not so kept;
- the company complied, in all material respects, with the Determination in preparing the audited Disclosure Information; and
- the company's basis for valuation of related party transactions in the disclosure year has complied, in all material respects, with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the IM Determination.

To meet these responsibilities, we planned and performed procedures in accordance with ISAE (NZ) 3000 (Revised) and SAE 3100 (Revised), to obtain reasonable assurance about whether the company has complied, in all material respects, with the Disclosure Information (which includes the Related Party Transaction Information) required to be audited by the Determination.

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

Inherent limitations

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

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

Restricted use

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

Independence and quality control

We complied with the Auditor-General's independence and other ethical requirements, which incorporate the requirements of Professional and Ethical Standard 1 International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand) as applicable for audits of public interest entities (PES 1) issued by the New Zealand Auditing and Assurance Standards Board. PES 1 is founded on the fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behaviour.

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

The Auditor-General, and his employees, and PricewaterhouseCoopers and its partners and employees may deal with the company on normal terms within the ordinary course of trading activities of the company. Other than any dealings on normal terms within the ordinary course of trading activities of the company, this engagement, the assurance engagement on the Default Price-Quality Path and the annual audit of the company's financial statements and performance information, we have no relationship with, or interests in, the company.

Elizabeth Adriana (Adri) Smit
PricewaterhouseCoopers
On behalf of the Auditor-General
Christchurch, New Zealand
28 August 2026

6. DIRECTORS' CERTIFICATE

Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2 and 2.9.5

We, Stephen Paul Lewis and Peter James Heenan, being directors of Electricity Invercargill Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) the information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.3.8 – 2.3.18, 2.4.21, 2.4.22, 2.5.1(1)(a)-(f), 2.5.2, 2.5.2A and 2.7.1 of the Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 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 Electricity Invercargill Limited's accounting and other records sourced from its financial and non-financial systems, and that sufficient appropriate records have been retained.

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

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

    ii. the 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.

Stephen Paul Lewis **Peter James Heenan**

26 August 2026

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