Electricity Invercargill Ltd

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

FOR THE YEAR ENDED 31 MARCH 2023

CONTENTS

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.

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 2023**

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

sch ref		Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
7	**1(i): Expenditure metrics**					
8						
9	**Operational expenditure**	22,360	318	77,877	8,406	35,799
10	Network	8,327	118	29,003	3,131	13,332
11	Non-network	14,033	200	48,874	5,275	22,467
12						
13	**Expenditure on assets**	21,193	301	73,813	7,967	33,931
14	Network	21,193	301	73,813	7,967	33,931
15	Non-network	–	–	–	–	–
16						

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
17	**1(ii): Revenue metrics**		
18			
19	**Total consumer line charge revenue**	73,809	1,050
20	Standard consumer line charge revenue	73,809	1,050
21	Non-standard consumer line charge revenue	–	–
22			

sch ref			
23	**1(iii): Service intensity measures**		
24			
25	Demand density	106	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	376	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	26	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	14,225	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

sch ref		($000)	% of revenue
30	**1(iv): Composition of regulatory income**		
31			
32	Operational expenditure	5,586	30.17%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	6,058	32.72%
34	Total depreciation	3,729	20.14%
35	Total revaluations	6,645	35.89%
36	Regulatory tax allowance	927	5.01%
37	Regulatory profit/(loss) including financial incentives and wash-ups	8,859	47.85%
38	**Total regulatory income**	18,514	
39			

sch ref			
40	**1(v): Reliability**		
41			
42	Interruption rate	7.22	*Interruptions per 100 circuit km*

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2023

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	5.65%	9.25%	8.77%
11	Excluding revenue earned from financial incentives	5.53%	9.50%	8.59%
12	Excluding revenue earned from financial incentives and wash-ups	5.53%	9.61%	8.70%
13				
14	**Mid-point estimate of post tax WACC**	3.72%	3.52%	4.88%
15	25th percentile estimate	3.04%	2.84%	4.20%
16	75th percentile estimate	4.40%	4.20%	5.56%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	5.98%	9.55%	9.28%
21	Excluding revenue earned from financial incentives	5.86%	9.80%	9.11%
22	Excluding revenue earned from financial incentives and wash-ups	5.86%	9.91%	9.21%
23				
24	**WACC rate used to set regulatory price path**	4.57%	4.57%	4.57%
25				
26	**Mid-point estimate of vanilla WACC**	4.05%	3.82%	5.39%
27	25th percentile estimate	3.37%	3.14%	4.71%
28	75th percentile estimate	4.73%	4.50%	6.07%
29				

sch ref				($000)	
30	**2(ii): Information Supporting the ROI**				
31					
32		Total opening RAB value	99,905		
33	*plus*	Opening deferred tax	(5,218)		
34	**Opening RIV**			94,688	
35					
36	**Line charge revenue**			18,439	
37					
38		Expenses cash outflow	11,644		
39	*add*	Assets commissioned	4,522		
40	*less*	Asset disposals	43		
41	*add*	Tax payments	364		
42	*less*	Other regulated income	75		
43	**Mid-year net cash outflows**			16,412	
44					
45	**Term credit spread differential allowance**			–	
46					
47		Total closing RAB value	107,300		
48	*less*	Adjustment resulting from asset allocation	0		
49	*less*	Lost and found assets adjustment	–		
50	*plus*	Closing deferred tax	(5,781)		
51	**Closing RIV**			101,519	
52					
53	**ROI – comparable to a vanilla WACC**				9.28%
54					
55		Leverage (%)			42%
56		Cost of debt assumption (%)			4.38%
57		Corporate tax rate (%)			28%
58					
59	**ROI – comparable to a post tax WACC**				8.77%
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	9.04%
Year-end ROI – comparable to a post tax WACC	8.53%

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

2(v): Financial Incentives and Wash-Ups

Net recoverable costs allowed under incremental rolling incentive scheme	217	
Purchased assets – avoided transmission charge	–	
Energy efficiency and demand incentive allowance		
Quality incentive adjustment	8	
Other financial incentives	–	
Financial incentives		225
Impact of financial incentives on ROI		0.18%
Input methodology claw-back	–	
CPP application recoverable costs	–	
Catastrophic event allowance	–	
Capex wash-up adjustment	(134)	
Transmission asset wash-up adjustment	–	
2013–15 NPV wash-up allowance	–	
Reconsideration event allowance	–	
Other wash-ups	–	
Wash-up costs		(134)
Impact of wash-up costs on ROI		–0.10%

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2023**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		18,439
10	*plus*	Gains / (losses) on asset disposals		12
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		63
12				
13		**Total regulatory income**		18,514
14		**Expenses**		
15	*less*	Operational expenditure		5,586
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		6,058
18				
19		**Operating surplus / (deficit)**		6,870
20				
21	*less*	Total depreciation		3,729
22				
23	*plus*	Total revaluations		6,645
24				
25		**Regulatory profit / (loss) before tax**		9,785
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		927
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		8,859
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	198	
36		Commerce Act levies	37	
37		Industry levies	61	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	5,425	
41		Transpower new investment contract charges	337	
42		System operator services	–	
43		Distributed generation allowance	–	
44		Extended reserves allowance	–	
45		Other recoverable costs excluding financial incentives and wash-ups	–	
46		**Pass-through and recoverable costs excluding financial incentives and wash-ups**		6,058
47				
48		**3(iii): Incremental Rolling Incentive Scheme**	**($000)**	
49			**CY-1**	**CY**
50				**31 Mar 23**
51		Allowed controllable opex	–	–
52		Actual controllable opex	–	–
53				
54		Incremental change in year		–
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57		CY-5 [year]	–	–
58		CY-4 [year]	–	–
59		CY-3 [year]	–	–
60		CY-2 [year]	–	–
61		CY-1 [year]	–	–
62		**Net incremental rolling incentive scheme**		–
63				
64		**Net recoverable costs allowed under incremental rolling incentive scheme**		–
65		**3(iv): Merger and Acquisition Expenditure**		
70				**($000)**
66		Merger and acquisition expenditure		–
67				
68		*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*		
69		**3(v): Other Disclosures**		
70				**($000)**
71		Self-insurance allowance		–

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2023

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)
Total opening RAB value	84,072	86,605	89,033	91,117	99,905
less **Total depreciation**	3,120	3,225	3,339	3,495	3,729
plus **Total revaluations**	1,245	2,191	1,353	6,303	6,645
plus **Assets commissioned**	4,533	3,587	4,132	6,117	4,522
less **Asset disposals**	126	125	62	137	43
plus **Lost and found assets adjustment**	–	–	–	–	–
plus **Adjustment resulting from asset allocation**	–	–	–	(0)	0
Total closing RAB value	86,605	89,033	91,117	99,905	107,300

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
Total opening RAB value		99,905		99,905
less				
Total depreciation		3,729		3,729
plus				
Total revaluations		6,645		6,645
plus				
Assets commissioned (other than below)	–		–	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	4,522		4,522	
Assets commissioned		4,522		4,522
less				
Asset disposals (other than below)	43		43	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	–		–	
Asset disposals		43		43
plus **Lost and found assets adjustment**		–		–
plus **Adjustment resulting from asset allocation**				0
Total closing RAB value		107,300		107,300

* *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

CPI_4	1,218
CPI_4^{-4}	1,142
Revaluation rate (%)	6.65%

	Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
Total opening RAB value	99,905		99,905	
less Opening value of fully depreciated, disposed and lost assets	61		61	
Total opening RAB value subject to revaluation	99,845		99,845	
Total revaluations		6,645		6,645

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction	Unallocated works under construction	Allocated works under construction	Allocated works under construction
Works under construction—preceding disclosure year		1,209		1,209
plus Capital expenditure	4,881		4,881	
less Assets commissioned	4,522		4,522	
plus Adjustment resulting from asset allocation			–	
Works under construction - current disclosure year		1,568		1,568
Highest rate of capitalised finance applied				–

4(v): Regulatory Depreciation

	Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
Depreciation - standard	3,729		3,729	
Depreciation - no standard life assets	–		–	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		3,729		3,729

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	1,333	7,097	21,953	2,569	45,279	11,007	7,176	3,491	–	99,905
less	Total depreciation	41	213	767	109	1,597	465	327	210	–	3,729
plus	Total revaluations	86	472	1,462	170	3,013	733	477	232	–	6,645
plus	Assets commissioned	120	52	756	220	1,146	423	1,739	66	–	4,522
less	Asset disposals	42	–	–	–	–	1	–	–	–	43
plus	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
plus	Asset category transfers	–	–	–	–	–	–	–	–	–	–
	Total closing RAB value	1,456	7,408	23,404	2,850	47,841	11,697	9,065	3,579	–	107,300

Asset Life

	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	
Weighted average remaining asset life	31.7	39.1	34.9	35.9	36.5	27.5	26.1	18.4	–	(years)
Weighted average expected total asset life	40.3	57.3	50.4	59.7	58.6	45.0	38.4	36.6	–	(years)

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2023**

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					
7	**5a(i): Regulatory Tax Allowance**				**($000)**
8		**Regulatory profit / (loss) before tax**			9,785
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	1,249		
13		Amortisation of revaluations	640		
14					1,889
15					
16	*less*	Total revaluations	6,645		
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	15	*	
20		Notional deductible interest	1,705		
21					8,365
22					
23		**Regulatory taxable income**			3,310
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			3,310
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			927
30					
31	* Workings to be provided in Schedule 14				
32	**5a(ii): Disclosure of Permanent Differences**				
33		In Schedule 14, Box 5, provide descriptions and workings of items recorded in the asterisked categories in Schedule 5a(i).			
34	**5a(iii): Amortisation of Initial Difference in Asset Values**				**($000)**
35					
36		Opening unamortised initial differences in asset values	18,729		
37	*less*	Amortisation of initial differences in asset values	1,249		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	–		
40		Closing unamortised initial differences in asset values			17,480
41					
42		Opening weighted average remaining useful life of relevant assets (years)			15
43					

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	83,466	
	Adjusted depreciation	3,089	
	Total depreciation	3,729	
	Amortisation of revaluations		640

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	(5,218)	
plus	Tax effect of adjusted depreciation	865	
less	Tax effect of tax depreciation	1,151	
plus	Tax effect of other temporary differences*	69	
less	Tax effect of amortisation of initial differences in asset values	350	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–	
less	Deferred tax balance relating to assets disposed in the disclosure year	(4)	
plus	Deferred tax cost allocation adjustment	(0)	
	Closing deferred tax		(5,781)

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	47,540	
less	Tax depreciation	4,112	
plus	Regulatory tax asset value of assets commissioned	4,940	
less	Regulatory tax asset value of asset disposals	27	
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		48,342

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2023**

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

sch ref	5b(i): Summary—Related Party Transactions	($000)	($000)
8	**Total regulatory income**		–
9			
10	**Market value of asset disposals**		–
11			
12	Service interruptions and emergencies	505	
13	Vegetation management	–	
14	Routine and corrective maintenance and inspection	1,365	
15	Asset replacement and renewal (opex)	210	
16	**Network opex**		2,080
17	Business support	1,815	
18	System operations and network support	362	
19	**Operational expenditure**		4,257
20	Consumer connection	704	
21	System growth	–	
22	Asset replacement and renewal (capex)	3,821	
23	Asset relocations	6	
24	Quality of supply	307	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	456	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		5,294
29	Cost of financing		–
30	Value of capital contributions		–
31	Value of vested assets		–
32	**Capital Expenditure**		5,294
33	**Total expenditure**		9,551
34			
35	**Other related party transactions**		–

36 5b(iii): Total Opex and Capex Related Party Transactions

37	Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
38	PowerNet Limited	Service interruptions and emergencies	505
39	PowerNet Limited	Routine and corrective maintenance and inspection	1,365
40	PowerNet Limited	Asset replacement and renewal (opex)	210
41	PowerNet Limited	System operations and network support	362
42	PowerNet Limited	Business support	1,661
43	Invercargill City Holdings	Business support	154
44	PowerNet Limited	Consumer connection	704
45	PowerNet Limited	Asset replacement and renewal (capex)	3,821
46	PowerNet Limited	Asset relocations	6
47	PowerNet Limited	Quality of supply	307
48	PowerNet Limited	Other reliability, safety and environment	456
49			
50			
51			
52			
53	**Total value of related party transactions**		9,551
54	** include additional rows if needed*		
55			

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2023**

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

This schedule is only to be completed if, as at the date of the most recently published financial statements, the weighted average original tenor of the debt portfolio (both qualifying debt and non-qualifying debt) is greater than five years.
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7

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

9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
11									
12									
13									
14									
15									
16	** include additional rows if needed*						–	–	–

17

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

19

sch ref			
20	**Gross term credit spread differential**		–
21			
22	Total book value of interest bearing debt		
23	Leverage	42%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		–
26			
27	**Term credit spread differential allowance**		–

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2023

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		505			
Not directly attributable				–	
Total attributable to regulated service		505			
Vegetation management					
Directly attributable					
Not directly attributable				–	
Total attributable to regulated service		–			
Routine and corrective maintenance and inspection					
Directly attributable		1,365			
Not directly attributable				–	
Total attributable to regulated service		1,365			
Asset replacement and renewal					
Directly attributable		210			
Not directly attributable				–	
Total attributable to regulated service		210			
System operations and network support					
Directly attributable		1,116			
Not directly attributable		–	–	–	
Total attributable to regulated service		1,116			
Business support					
Directly attributable		1,888			
Not directly attributable		502	37	539	
Total attributable to regulated service		2,390			
Operating costs directly attributable		5,084			
Operating costs not directly attributable	–	502	37	539	–
Operational expenditure		5,586			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	($000)
Pass through costs	
Directly attributable	296
Not directly attributable	–
Total attributable to regulated service	296
Recoverable costs	
Directly attributable	5,762
Not directly attributable	–
Total attributable to regulated service	5,762

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

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

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

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

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

Company Name **Electricity Invercargill Limited**
For Year Ended **31 March 2023**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

This schedule requires information on the allocation of asset values. This information supports the calculation of the RAB value in Schedule 4.
EDBs must provide explanatory comment on their cost allocation in Schedule 14 (Mandatory Explanatory Notes), including on the impact of any changes in asset allocations. This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7 5e(i): Regulated Service Asset Values

sch ref		Value allocated ($000s) Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	1,456
12	Not directly attributable	–
13	**Total attributable to regulated service**	1,456
14	**Subtransmission cables**	
15	Directly attributable	7,408
16	Not directly attributable	–
17	**Total attributable to regulated service**	7,408
18	**Zone substations**	
19	Directly attributable	23,404
20	Not directly attributable	–
21	**Total attributable to regulated service**	23,404
22	**Distribution and LV lines**	
23	Directly attributable	2,850
24	Not directly attributable	–
25	**Total attributable to regulated service**	2,850
26	**Distribution and LV cables**	
27	Directly attributable	47,841
28	Not directly attributable	–
29	**Total attributable to regulated service**	47,841
30	**Distribution substations and transformers**	
31	Directly attributable	11,697
32	Not directly attributable	–
33	**Total attributable to regulated service**	11,697
34	**Distribution switchgear**	
35	Directly attributable	9,065
36	Not directly attributable	–
37	**Total attributable to regulated service**	9,065
38	**Other network assets**	
39	Directly attributable	3,579
40	Not directly attributable	–
41	**Total attributable to regulated service**	3,579
42	**Non-network assets**	
43	Directly attributable	–
44	Not directly attributable	–
45	**Total attributable to regulated service**	–
46		
47	**Regulated service asset value directly attributable**	107,300
48	**Regulated service asset value not directly attributable**	–
49	**Total closing RAB value**	107,300

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

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

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

Company Name **Electricity Invercargill Limited**
For Year Ended **31 March 2023**

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											
7											
8											
9					Allocator Metric (%)		Value allocated ($000)				
10	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	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	**System operations and network support**										
37										-	
38										-	
39										-	
40										-	
41	**Not directly attributable**						-	-	-	-	-
42	**Business support**										
43	Administration Expenses	ABAA	Revenue	Proxy	93.24%	6.76%	-	502	37	539	
44										-	
45										-	
46										-	
47	**Not directly attributable**						-	502	37	539	-
48											
49	**Operating costs not directly attributable**						-	502	37	539	-
50											
51	**Pass through and recoverable costs**										
52	**Pass through costs**										
53										-	
54										-	
55										-	
56										-	
57	**Not directly attributable**						-	-	-	-	-
58	**Recoverable costs**										
59										-	
60										-	
61										-	
62										-	
63	**Not directly attributable**						-	-	-	-	-
64	** include additional rows if needed*										

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2022

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

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

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

sch ref					Allocator Metric (%)		Value allocated ($000)				
7											
8											
9–10	Line Item*	Allocation methodology type	Allocator	Allocator type	Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	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 2023

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				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		704
9		System growth		–
10		Asset replacement and renewal		3,821
11		Asset relocations		6
12		Reliability, safety and environment:		
13		Quality of supply	307	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	456	
16		**Total reliability, safety and environment**		763
17		**Expenditure on network assets**		5,294
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		5,294
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		413
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		4,881

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

30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Customer Connections < 20 kVA	88	
33		Customer Connections 21 - 99 kVA	28	
34		Customer Connections > 100 kVA	400	
35		Distributed Generation Connection	1	
36		New Subdivisions	187	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		704
39				
40	*less*	Capital contributions funding consumer connection expenditure	343	
41		**Consumer connection less capital contributions**		361

42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement**
43			**System Growth**	**and Renewal**
44			**($000)**	**($000)**
45		Subtransmission	–	–
46		Zone substations	–	538
47		Distribution and LV lines	–	152
48		Distribution and LV cables	–	617
49		Distribution substations and transformers	–	621
50		Distribution switchgear	–	1,893
51		Other network assets	–	–
52		**System growth and asset replacement and renewal expenditure**	–	3,821
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	69
54		**System growth and asset replacement and renewal less capital contributions**	–	3,752
55				

56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58			–	
59			–	
60			–	
61			–	
62			–	
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	6	
65		**Asset relocations expenditure**		6
66	*less*	Capital contributions funding asset relocations	1	
67		**Asset relocations less capital contributions**		5

68				
69		**6a(vi): Quality of Supply**		
70		*Project or programme**	($000)	($000)
71		Supply Quality Upgrades - Bluff	2	
72		Network Automation Projects	143	
73		Fault Indicator Project	162	
74			–	
75			–	
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	–	
78		**Quality of supply expenditure**		307
79	*less*	Capital contributions funding quality of supply	–	
80		**Quality of supply less capital contributions**		307
81		**6a(vii): Legislative and Regulatory**		
82		*Project or programme**	($000)	($000)
83			–	
84			–	
85			–	
86			–	
87			–	
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory	–	
90		**Legislative and regulatory expenditure**		–
91	*less*	Capital contributions funding legislative and regulatory	–	
92		**Legislative and regulatory less capital contributions**		–
93		**6a(viii): Other Reliability, Safety and Environment**		
94		*Project or programme**	($000)	($000)
95		Earth Upgrades - City	308	
96		Pillar Box Lid Upgrade	23	
97		Fibre Installation	41	
98		LV Tie Point Disconnectors	32	
99		Oil-Filled Cable Work	52	
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	–	
102		**Other reliability, safety and environment expenditure**		456
103	*less*	Capital contributions funding other reliability, safety and environment	–	
104		**Other reliability, safety and environment less capital contributions**		456
105				
106		**6a(ix): Non-Network Assets**		
107		**Routine expenditure**		
108		*Project or programme**	($000)	($000)
109			–	
110			–	
111			–	
112			–	
113			–	
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure	–	
116		**Routine expenditure**		–
117		**Atypical expenditure**		
118		*Project or programme**	($000)	($000)
119			–	
120			–	
121			–	
122			–	
123			–	
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure	–	
126		**Atypical expenditure**		–
127				
128		**Expenditure on non-network assets**		–

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2023

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

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

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	505	
9	Vegetation management	–	
10	Routine and corrective maintenance and inspection	1,365	
11	Asset replacement and renewal	210	
12	**Network opex**		2,080
13	System operations and network support	1,116	
14	Business support	2,390	
15	**Non-network opex**		3,506
16			
17	**Operational expenditure**		5,586
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	*EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*		
20	Energy efficiency and demand side management, reduction of energy losses		63
21	Direct billing*		–
22	Research and development		–
23	Insurance		164
24	Cybersecurity (Commission only)		–
25	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2023

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	18,817	18,439	(2%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	689	704	2%
11	System growth	–	–	–
12	Asset replacement and renewal	3,649	3,821	5%
13	Asset relocations	6	6	0%
14	Reliability, safety and environment:			
15	Quality of supply	353	307	(13%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	688	456	(34%)
18	**Total reliability, safety and environment**	1,041	763	(27%)
19	**Expenditure on network assets**	5,385	5,294	(2%)
20	Expenditure on non-network assets	–	–	–
21	Expenditure on assets	5,385	5,294	(2%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	517	505	(2%)
24	Vegetation management	7	–	(100%)
25	Routine and corrective maintenance and inspection	1,464	1,365	(7%)
26	Asset replacement and renewal	232	210	(10%)
27	**Network opex**	2,220	2,080	(6%)
28	System operations and network support	1,255	1,116	(11%)
29	Business support	2,181	2,390	10%
30	**Non-network opex**	3,436	3,506	2%
31	**Operational expenditure**	5,656	5,586	(1%)
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	–	–
34	Overhead to underground conversion	–	–	–
35	Research and development	–	–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	125	63	(50%)
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	149	164	10%
42				

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

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

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2023**
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Low user	Residential	Standard	6,368	40,483
Domestic	Residential	Standard	9,103	90,218
Non-Domestic	Commerical	Standard	1,919	45,382
Individual non half hour	Commerical	Standard	40	5,446
Individual half hour	Commerical	Standard	132	68,290
		Standard consumer totals	17,562	249,819
		Non-standard consumer totals	–	–
		Total for all consumers	17,562	249,819

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

Billed quantities by price component

Price component	Variable day energy sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases		
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh		
Low user		16,983,348	14,878,885	10,333,035		
Domestic		37,844,502	33,537,795	23,740,149		
Non-Domestic		19,037,448	16,811,347	11,830,966		
Individual non half hour		2,284,494	2,017,362	1,419,716		
Individual half hour	49,688,758					
Standard consumer totals	49,688,758	76,149,792	67,245,388	47,323,866	–	–
Non-standard consumer totals	–	–	–	–	–	–
Total for all consumers	49,688,758	76,149,792	67,245,388	47,323,866	–	–

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	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Line charge revenues ($000) by price component					
						Price component	Fixed	Variable Day energy Sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases	
						Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kWh	$/kWh	$/kWh	$/kWh	
Low user	Residential	Standard	$3,580		$2,600	$980	$503		$1,771	$1,202	$103	
Domestic	Residential	Standard	$7,480		$5,419	$2,061	$2,835		$2,529	$1,878	$237	
Non-Domestic	Commerical	Standard	$4,124		$2,989	$1,135	$1,786		$1,278	$941	$118	
Individual non half hour	Commerical	Standard	$357		$222	$135	$76		$153	$113	$14	
Individual half hour	Commerical	Standard	$2,899		$1,448	$1,451	$1,492		$1,407			
			–									
			–									
			–									
			–									
			–									
		Standard consumer totals	$18,439	–	$12,677	$5,762	$6,693	$1,407	$5,731	$4,135	$473	–
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	$18,439	–	$12,677	$5,762	$6,693	$1,407	$5,731	$4,135	$473	–

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

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

Check: OK

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 2023**
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	733	738	5	3
10	All	Overhead Line	Wood poles	No.	204	202	(2)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1	1	0	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.	51	51	–	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	22	22	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	64	66	2	3
39	HV	Distribution Cable	Distribution UG PILC	km	96	94	(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.	73	73	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	52	61	9	3
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.	451	455	4	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	10	10	–	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	418	437	19	4
48	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	N/A
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	41	40	(1)	3
50	LV	LV Line	LV OH Conductor	km	30	30	(0)	3
51	LV	LV Cable	LV UG Cable	km	424	425	1	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	170	170	(0)	2
53	LV	Connections	OH/UG consumer service connections	No.	17,932	17,929	(3)	4
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	175	174	(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 2023
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

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940–1949	1950–1959	1960–1969	1970–1979	1980–1989	1990–1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
8		Disclosure Year (year ended)																																							
10	All	Overhead Line	Concrete poles / steel structure	No.	–	–	–	321	6	–	1	2	4	2	–	6	3	4	2	11	5	22	97	34	74	17	23	26	30	8	9	6	9	10	–	–	–	6	738		3
11	All	Overhead Line	Wood poles	No.	–	–	–	150	1	–	2	11	11	4	6	6	4	2	1	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	2	202		3
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	–	–	–	–	–	–	–	–	–	–	–	15		4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	5	7	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	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	–	–	–	–	–	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	16	–	–	–	–	5	3	–	–	–	–	–	51		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	2	1	–	–	–	1	–	–	–	–	–	–	–	–	–	–	1	–	1	–	–	–	–	–	–	–	–	–	–	–	7		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0	–	0	11	4	2	3	1	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	1	0	–	–	–	0	–	–	–	–	0	22		3
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	5	2	2	1	2	0	5	3	1	1	2	1	1	2	0	–	–	4	66		3
40	HV	Distribution Cable	Distribution UG PILC	km	0	–	0	13	23	32	18	3	2	–	0	0	1	–	0	2	–	–	–	0	–	–	0	–	0	–	–	–	–	0	–	–	–	0	94		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.	–	–	–	6	1	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4	9	17	8	13	5	8	–	–	–	–	–	73		4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.			1	8	1	3	–	–	1	1	1	–	–	1	–	1	1	1	2	–	3	–	3	3	3	5	1	5	10	–	–	–	–	6	61		3
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.	–	–	–	11	34	114	53	10	17	17	5	7	14	7	15	24	16	9	12	5	4	4	10	10	11	7	8	10	5	13	2	–	–	1	455		4
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	1	2	1	–	–	–	1	1	–	–	–	1	–	1	1	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	10		4
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	5	30	28	61	66	7	12	13	10	8	16	11	8	10	13	14	19	19	10	14	13	6	10	4	12	5	6	2	5	–	–	–	437		4
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	1	9	1	14	5	1	2	–	1	–	1	1	1	–	–	–	2	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	40		3
51	LV	LV Line	LV OH Conductor	km	–	–	0	4	0	2	1	16	–	3	1	0	0	0	–	0	–	–	0	0	0	0	0	0	0	0	0	0	0	0	–	–	–	0	30		3
52	LV	LV Cable	LV UG Cable	km	1	–	9	46	73	110	64	12	16	21	3	10	6	9	4	7	6	3	5	2	1	1	2	3	4	2	2	0	1	1	0	–	–	2	425		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	2	0	1	15	4	22	89	19	2	1	0	0	1	1	1	2	1	1	1	0	2	1	0	1	0	0	0	0	1	0	0	–	–	2	170		2
54	LV	Connections	OH/UG consumer service connections	No.	–	3	114	2,220	3,962	3,588	5,450	40	54	60	197	258	278	198	211	128	100	101	97	83	57	63	73	83	62	53	67	70	116	94	28	–	–	21	17,929		4
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	3	31	30	1	4	–	–	1	–	–	–	–	–	–	–	–	–	–	2	33	12	5	5	10	17	12	4	1	–	–	3	174		4
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	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 2023**
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	–	–	–
13	33kV	1	27	28
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	22	160	182
17	Low voltage (< 1kV)	30	425	454
18	**Total circuit length (for supply)**	53	612	665
19				
20	Dedicated street lighting circuit length (km)	25	146	170
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	49	93%	
25	Rural	2	3%	
26	Remote only	–	–	
27	Rugged only	2	4%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	53	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	664	100%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	4	8%	

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2023**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

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

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

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2023
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
8	**9e(i): Consumer Connections and Decommissionings**			
9	*Number of ICPs connected during year by consumer type*			
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**		
11	Domestic	85		
12	Non Domestic	18		
13	Half Hour Individual	4		
14				
15				
16	** include additional rows if needed*			
17	**Connections total**	107		
18				
19	*Number of ICPs decommissioned during year by consumer type*			
20	*Consumer types defined by EDB**	**Number of decommissionings**		
21	Low User	3		
22	Domestic	8		
23	Non Domestic	31		
24	Half Hour Individual	3		
25				
26	** include additional rows if needed*			
27	**Decommissionings total**	45		
28				
29	**Distributed generation**			
30	Number of connections made in year	6.0	**connections**	
32	Capacity of distributed generation installed in year	0.0	**MVA**	
33				
34	**9e(ii): System Demand**			
35				
36				
37	**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**		
38	GXP demand	70.2		
39	*plus* Distributed generation output at HV and above	–		
40	**Maximum coincident system demand**	70		
41	*less* Net transfers to (from) other EDBs at HV and above	(1.5)		
42	**Demand on system for supply to consumers' connection points**	72		
43	**Electricity volumes carried**	**Energy (GWh)**		
44	Electricity supplied from GXPs	249		
45	*less* Electricity exports to GXPs	–		
46	*plus* Electricity supplied from distributed generation	0.30		
47	*less* Net electricity supplied to (from) other EDBs	(13)		
48	**Electricity entering system for supply to consumers' connection points**	262		
49	*less* Total energy delivered to ICPs	250		
51	**Electricity losses (loss ratio)**	12		4.6%
52				
53	**Load factor**	0.42		
54	**9e(iii): Transformer Capacity**			
55		**(MVA)**		
56	Distribution transformer capacity (EDB owned)	156		
57	Distribution transformer capacity (Non-EDB owned, estimated)	2		
58	**Total distribution transformer capacity**	158		
59				
60	**Zone substation transformer capacity**	94		
61				

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2023**
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

sch ref	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	21
12	Class C (unplanned interruptions on the network)	24
13	Class D (unplanned interruptions by Transpower)	–
14	Class E (unplanned interruptions of EDB owned generation)	–
15	Class F (unplanned interruptions of generation owned by others)	–
16	Class G (unplanned interruptions caused by another disclosing entity)	3
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	48

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	14	10

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.0812	27.75
27	Class C (unplanned interruptions on the network)	0.4911	35.74
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	0.0814	2.10
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	0.6537	65.59

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	0.5723	63.50

39 Transitional SAIDI and SAIDI (previous method)

40 *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.***

sch ref		SAIFI	SAIDI
41	Class B (planned interruptions on the network)	n/a	n/a
42	Class C (unplanned interruptions on the network)	n/a	n/a

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

sch ref	Cause	SAIFI	SAIDI
47	Lightning	–	–
48	Vegetation	–	–
49	Adverse weather	0.0208	2.63
50	Adverse environment	–	–
51	Third party interference	0.1126	1.64
52	Wildlife	0.0044	0.13
53	Human error	0.0027	0.05
54	Defective equipment	0.3498	31.05
55	Cause unknown	0.0008	0.24

sch ref	Breakdown of third party interference	SAIFI	SAIDI
58	Dig-in	n/a	n/a
59	Overhead contact	n/a	n/a
60	Vandalism	n/a	n/a
61	Vehicle damage	n/a	n/a
62	Other	n/a	n/a

64 10(iii): Class B Interruptions and Duration by Main Equipment Involved

sch ref	Main equipment involved	SAIFI	SAIDI
67	Subtransmission lines	–	–
68	Subtransmission cables	–	–
69	Subtransmission other	–	–
70	Distribution lines (excluding LV)	0.0190	6.82
71	Distribution cables (excluding LV)	0.0051	1.40
72	Distribution other (excluding LV)	0.0571	19.53

73 10(iv): Class C Interruptions and Duration by Main Equipment Involved

sch ref	Main equipment involved	SAIFI	SAIDI
76	Subtransmission lines	–	–
77	Subtransmission cables	–	–
78	Subtransmission other	–	–
79	Distribution lines (excluding LV)	0.0836	9.58
80	Distribution cables (excluding LV)	0.3012	22.87
81	Distribution other (excluding LV)	0.1063	3.29

82 10(v): Fault Rate

sch ref	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
84	Subtransmission lines	–	1	–
85	Subtransmission cables	–	27	–
86	Subtransmission other	–		
87	Distribution lines (excluding LV)	9	22	41.04
88	Distribution cables (excluding LV)	6	160	3.75
89	Distribution other (excluding LV)	9		
90	**Total**	24		

SCHEDULE 14 MANDATORY EXPLANATORY NOTES

1. This schedule requires EDBs to provide explanatory notes to information provided in accordance with clauses 2.3.1, 2.4.21, 2.4.22, and subclauses 2.5.1(1)(f),and 2.5.2(1)(e).

2. This schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 11 of this schedule is part of the audited disclosure information, and so is subject to the assurance requirements specified in section 2.8.

3. Schedule 15 (Voluntary Explanatory Notes to Schedules) provides for EDBs to give additional explanation of disclosed information should they elect to do so.

- *Return on Investment (Schedule 2)*

4. In the box below, comment on return on investment as disclosed in Schedule 2. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 1: Explanatory comment on return on investment

Electricity Invercargill Limited achieved a post-tax ROI of 8.77% which is above the 75th percentile estimate of post-tax WACC of 5.56% and a 9.28% vanilla ROI which is above the 75th percentile estimate of vanilla WACC of 6.07%.

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

Included in other regulated income is an amount of $59k for line charges and $4k for Fibre charges to another lines company.

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 2022 closing figure of $99,905k as a starting point with inflationary indexing over the year to 31 March 2023, plus additions less disposals. This resulted in a closing RAB balance of $107,300k. 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 $15k 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:	$	245
	$	245
Tax Rate:		28%
Temporary Differences	$	69

-

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

Reactive and minor maintenance is performed on Electricity Invercargill Limited's transformers and cables and this is classified as refurbishment and renewal maintenance when the work performed is not material in relation to the overall value of the asset.

No items were reclassified during the disclosure year.

There have been no material items of atypical expenditure during the year.

- *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 2% below budget.

Consumer connection:
- 2% overspend due to higher number of new customer connections completed this year than planned.

Asset replacement and renewal:
- 5% overspend due to CBD cable upgrades carried over from last year and increased spend on link box replacements due to fault.

Asset Relocations:
- The spend was within the budget.

Quality of Supply:
- 13% underspend due to lack of identified supply quality issues identified and RMU automation was delayed due to supply issues.

Reliability, Safety and Environment:
- 34% underspend due to supply chain issues which restricted pillar box lids and some works on CBD network earthing upgrades deferred to next year.

Operational Expenditure:

The actual operational expenditure was 1% below budget.

Service interruptions and emergencies:
- 2% underspend which is a minor variation as a result of fewer faults.

Vegetation management:
- A reactive budget of $7k but no work was identified.

Routine and corrective maintenance and inspection:
- 7% underspend due to limited work identified from the inspection programme.

Asset replacement and renewal:
- 10% underspend due to RMU works programme were accelerated last year resulting to less work required during the year.

Non-network opex:
- 2% overspent which is a minor variation representing $70k more operation expenditure during the year. The system operations and network support underspent of 11% and business support overspent by 10% were off-setting variances due to management fee actual allocation not reflected in the budget.

- *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 $18,817k. The total billed revenue for the year was $18,439k, which is $378k below. The electricity consumption was impacted by the unseasonal warm weather during the winter season. This reduced the underlying line charge revenue, making it slightly lower (2% 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 consistent with the 2012 Electricity Distribution Business (EDB) ID Determination, with all amendments to 6 July 2023. Note that EIL has counted the successive interruptions within the initial interruption when calculating SAIFI in line with previous years.

EIL has disclosed a normalised SAIDI at 63.50 minutes and normalised SAIFI at 0.57 times for 2022/23. The normalised SAIFI is 50% lower than the 2021/22 year, with normalised SAIDI 40% lower. EIL published ID Determination values for normalised SAIDI of 105.2 and normalised SAIFI of 1.15 for the 2021/22 year – meaning less interruptions, with each being shorter duration compared with last year.

Class C (unplanned) interruption SAIDI decreased from 77.1 to 35.7 minutes and the actual number of Class C interruptions decreased from 37 to 24.

The total number of interruptions on EIL is lower than 2021/22 – with decreases in both Class B (planned) and Class C interruptions. The number of interruptions exceeding 3 hours duration also decreased.

Class C SAIFI of 0.49 was the major contributor to overall SAIFI, with a decrease of 53% from 2021/22, Class C SAIDI was 54% lower and Class B SAIDI was 2% lower than 2021/22.

The most significant cause of Class C interruptions was defective equipment which significantly decreased in frequency and duration compared with last year. Third party interference and adverse weather were also high contributors to Class C SAIDI.

Only 10% of EIL’s network is distribution lines, with 24% of planned interruptions and 27% of unplanned interruptions occurred on these lines based on SAIDI.

Distribution line fault rates per 100km improved from 68.18 in 2021/22 to 41.04, with distribution cable improving from 5.63 in 2021/22 to 3.75. 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. This makes 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 $30.5 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.)

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

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

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

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

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

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)

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

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

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 2021:

	2023	2024	2025	2026	2027
Inflator (CAPEX & OPEX)	5.1%	3.1%	2.7%	2.4%	2.2%

In addition to the general inflation, material costs have increased by a weighted average of 17% in 2021. This was included in the CAPEX forecasts for 2022 onwards.

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.)

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

   5.1 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;

   5.2 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.

6. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Schedule 10

Network reliability is compliant with quality requirements under DPP3, however due to the manual nature of the outage reporting process, there are inherent limitations in the ability of EIL to collect and record the network reliability information required to be disclosed in Schedule 10 (i) to 10 (iv). 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.

Several actions and initiatives are being taken to overcome limitations, including roll out and/or access to smart meter data, strengthening of processes relating to the recording of outages from the outage system, and retention of documentation.

4. APPENDIX - Related Party Transaction: Additional Information Disclosure

4.1 INTRODUCTION

For the purpose of meeting the 2023 Related Party Transaction reporting requirements, in accordance with section 2.3.6 of the Electricity Information Disclosure Determination 2012, (Consolidated in 2023), issued 6 July 2023.

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

- **Electricity Invercargill Limited's 2023 Information Disclosure**, for the year ended 31 March 2023 - 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 Electricity Invercargill Limited (EIL) being less than $20 million, for the year ending 31 March 2023.

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

Electricity Invercargill Limited (EIL) has an interest in PowerNet Limited, the OtagoNet Joint Venture, Lakeland Network Limited, and the Southern Generation Limited Partnership through their wholly owned subsidiary company Pylon Limited.

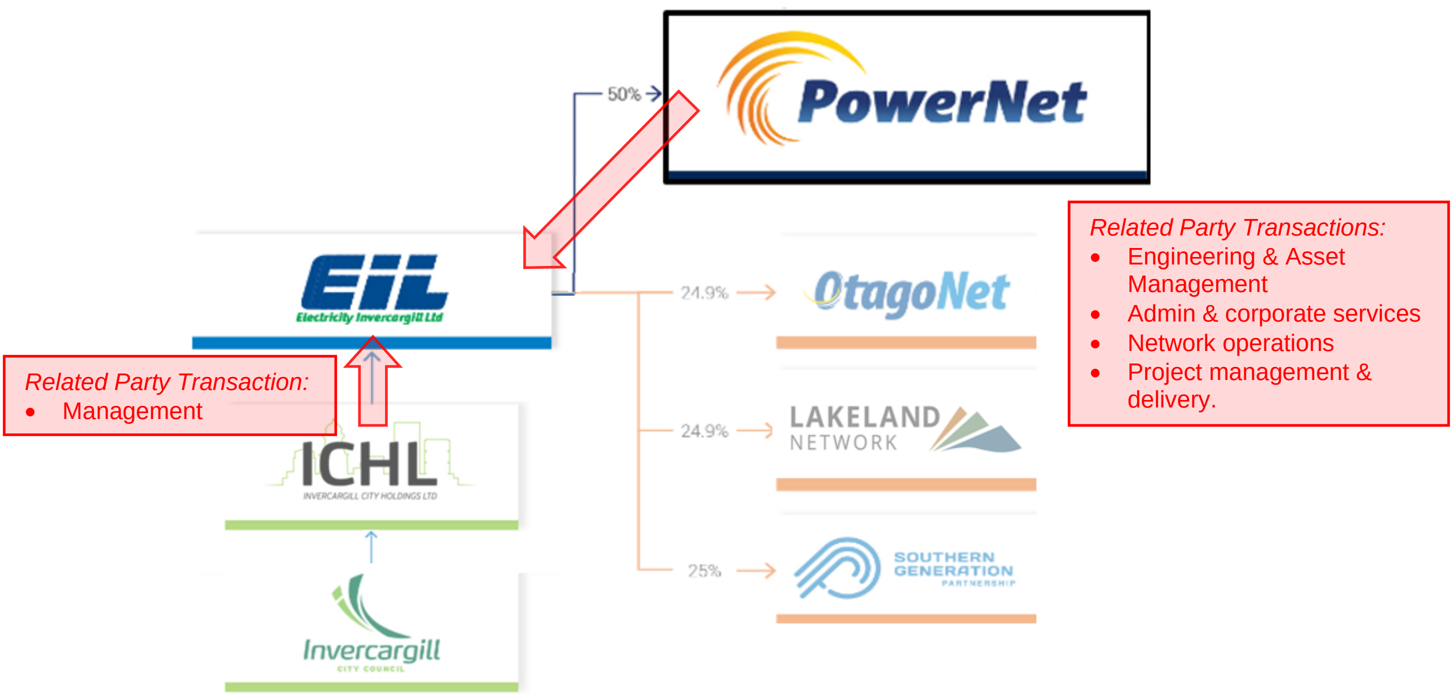
During the year, EIL had related party transactions with the following entities:

- Goods and services provided by – PowerNet Limited; Invercargill City Holdings Limited

The transactions between EIL and PowerNet are subject to Related Party Transaction reporting.

Company Structure

Electricity Invercargill Limited (EIL) is wholly-owned by the Invercargill City Council through its subsidiary company, Invercargill City Holdings Limited. The following diagram illustrates EIL's ownership interests in PowerNet and other related entities in the EIL Group, and the nature of related party transaction work undertaken.



a. **PowerNet Limited**

EIL holds a 50% shareholding in electricity network management company PowerNet Limited. PowerNet provides a range of field contracting, asset management, system control and finance and commercial services to EIL. The value of the related party transactions for the year ended 31 March 2023 is categorised as follows:

		($'000)
Operating Expenditure:		
i.	Service interruptions and emergencies	505
ii.	Routine and corrective maintenance and inspection	1,365
iii.	Asset replacement and renewal (opex)	210
iv.	Business support	1,661
v.	System operations and network support	362
Capital Expenditure		
i.	Consumer Connection	704
ii.	Asset replacement and renewal (capex)	3,821
iii.	Asset relocations	6
iv.	Quality of supply	307
v.	Other reliability, safety and environment	456
	Total Related Party expenditure from PowerNet	**9,397**

In the year ended 31 March 2023, PowerNet provided 100% of the EIL Lines Business Capital Expenditure, and 73% of all Operating Expenditure. The high percentage of related party transactions relative to total expenditure is due to PowerNet operating under a Network Management Agreement (NMA) with EIL, in the form of an "agency agreement".

Services provided under the agreement include:

- Electricity distribution field services
- System control services
- Project management of capital and maintenance work
- Faults restoration and stand by (on call) arrangements
- Asset management for EDB and meters,
- Heath, Safety and Environment management
- Business support, IT support and human resources
- Corporate, finance and commercial services

b. Invercargill City Holdings Limited

EIL is owned 100% by Invercargill City Holdings Limited (ICHL). The role of ICHL is to provide governance, funding and treasury support to the subsidiary companies they own.
The value of the related party transactions between ICHL and EIL for the year ended 31 March 2023 is categorised as follows:

		($'000)
Operating Expenditure:		
i.	Business support	155
	Total Related Party expenditure from ICHL	**155**

In the year to 31 March 2023, ICHL provided 3% of all Operating Expenditure, relating to management fees.

Network Management Agreement

EIL incurs 100% of its capital expenditure and a high percentage of its operating costs for its electricity distribution and meter businesses from PowerNet, in accordance with the explicit terms and conditions of the PowerNet Network Management Agreement (NMA).

While EIL owns the Network Assets and provides Line Function Services in Invercargill city and the Bluff township area, under the agreement PowerNet will manage the network assets, have right to carry out an agreed Capital Works programme, have the exclusive right to provide Line Function Services, and have the right to provide the business administration services on behalf of EIL.

PowerNet was established in 1994 to extract operational efficiencies from the merger of field work management, asset management and office based functions performed by EIL and The Power Company Limited (TPCL). In 1993, there were two autonomous Lines Companies in Southland (EIL and TPCL). Each had separate staff, management and Board of Directors, and each had a different ownership structure. Directors of both companies recognised there would be significant economies of scale benefits if there were a single Lines company covering the area. Due to different ownership a single Lines company was not possible, however a single network management entity was a viable option.

The ongoing drive for efficiency by merging operations and achieving scale was recently identified by the Government Pricing Review and the terms of reference required investigation into the "PowerNet model" as the review looked at how other EDBs could potentially do the same.

PowerNet charges Management Fees to the EDB's and metering businesses it manages under the NMA's. These charges recover costs incurred in the performance of the system control services, asset management, corporate, finance and commercial services.

These costs are charged to customers based on a cost allocation methodology applied within PowerNet. The allocation is based on various allocation drivers, including field operating orders, staff numbers, EDB asset size, EDB customers and a departmental assessment of indirect labour time splits. The allocation forms the basis of costs recovered from:

- the agency fee to be charged to the EDB's and metering businesses and
- the capital mark-up to recover costs allocated to EDB and meter capital projects

An independent review in 2022 of the allocation methodology ensured all parties that are charged network management fees and other fees by PowerNet are treated consistently and appropriately for each party.

Arm's Length Requirement

EIL believes the related party work performed by PowerNet is performed on an 'arm's-length' basis as if EIL and PowerNet were acting as willing buyer and willing seller, acting with independence and in pursuit of their own interests.

This view is based on the following reasons and best intent:

- Cost efficiencies and operating efficiencies generated from economies of scale;
- Cost efficiencies gained through supplier agreements eg Corys Electrical supply agreement with pricing mechanisms ensuring prices are maintained at a market competitive level;
- Separate entities operating with clear separation of duties and responsibilities;
- Two independent EDB entities with independent Directors acting in the best interests of their own business, owning and governing PowerNet;
- Relative labour costs benchmarking closely (+/-15%) within the average of alternate external supplier rates provided over the past two years;
- Market testing through tendering processes;
- External non-network customer work being awarded to PowerNet based on the same internal rates as charged to the EDB customers;
- Large percentage of Works Programme costs charged to EIL (over 50% of Capital and Maintenance work combined) are sourced from external suppliers, on a traditional arm's length transaction basis;
- Transparency of cost allocation process and mark-up rate agreed between the PowerNet EDB customers;
- Independent assessments of PowerNet performance and rates charged to EIL, providing favourable outcomes.

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 2023 as required by the Electricity Distribution Information Disclosure Determination 2012 (Consolidated 6 July 2023)

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

The Auditor-General is the auditor of the Company.

The Auditor-General has appointed me, 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 2023 (the Disclosure Information) complies, in all material respects, with the Determination.

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

- Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10 and 14 (limited to the explanatory notes in boxes 1 to 11) of the Determination.
- Clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 20 May 2020) (the IM Determination), in respect of the basis for valuation of related party transactions (the Related Party Transaction Information).

This assurance report should be read in conjunction with the Commerce Commission's Information Disclosure exemption, issued to all electricity distribution businesses on 26 May 2023 under clause 2.11.1 of the Determination. The Commerce Commission granted an exemption from the requirement that the assurance report, in respect of the information in Schedule 10 of the Determination, must take into account any issues arising out of the Company's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

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, in all material respects, with the Determination; and
- the basis for valuation of related party transactions complies with the Determination and the IM Determination.

Basis for 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(iv). 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(iv).

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(iv).

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

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

<table>
<tr><th>Key Assurance Matter</th><th>How our procedures addressed the key assurance matter</th></tr>
<tr><td>Regulatory asset base
The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of Electricity Invercargill Limited’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 Electricity Invercargill Limited’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.</td><td>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 inspected the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB;
• We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions disclosed in the audited annual financial statements and investigated any material reconciling items; and
• We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification.

Depreciation
• We compared the spreadsheet formula utilised to calculate regulatory depreciation expense with IM Determination clause 2.2.5;
• We compared the standard asset lives by asset category to those set out in the IM Determination; and</td></tr>
</table>

Key Assurance Matter	How our procedures addressed the key assurance matter
	● We have performed a reasonableness test to ensure regulatory depreciation expense is calculated in line with IM Determination clause 2.2.5. **Revaluation** ● We recalculated the revaluation rate set out in the IM Determination using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; and ● We tested the mathematical accuracy of the revaluation calculation performed by management. **Disposals** ● We reconciled the disposals, as per the regulatory fixed asset register, to the asset disposals disclosed in the audited annual financial statements and investigated any material reconciling items; and ● We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the IMs;
Related party transactions Disclosures over related party transactions including related party relationships, procurement policies/processes, application of these policies/processes and examples of market testing of transaction terms as required under the Determination and the IM Determination are set out in the Appendix. The Determination and the IM Determination require Electricity Invercargill Limited to value its transactions with related parties, disclosed in Schedule 5b, in accordance with the principles-based approach to the arm's length valuation rule. This rule states that the value of goods or services acquired from a related party cannot be greater than if it had been acquired under the terms of an arm's length transaction with an unrelated party, nor may it exceed the actual cost to the related party. A sale or supply to a related party cannot be valued at an amount less than if it had been sold or supplied under the terms of an arm's-length transaction with an unrelated party.	We have obtained an understanding of the compliance requirements relevant to related party transactions as set out in the Determination and the IM Determination. We have ensured Schedule 5(b) and the Appendix includes all required disclosures including current procurement policies, descriptions of how they are applied in practice, representative example transactions and when and how market testing was last performed. Our procedures over the related party transactions included the following: **Completeness and accuracy of related party relationships and transactions** We have tested the completeness and accuracy of the related party relationships and transactions by: ● Agreeing the disclosures within Schedule 5(b) to the audited financial statements for the year ended 31 March 2023 and to the accounting records, investigating any material differences and determining whether any such differences are justified; and ● Applying our understanding of the business structure against the related party definition in IM Determination clause 1.1.4(2)(b) to assess management's identification of any "unregulated parts" of the entity. **Practical application of procurement policies** ● Testing a sample of operating expenditure and capital expenditure transactions disclosed in

Key Assurance Matter	How our procedures addressed the key assurance matter
Arm's-length valuation, as defined in the IM Determination, is the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests. Electricity Invercargill Limited is required to use an objective and independent measure to demonstrate compliance with the arm's-length principle. In the absence of an active market for similar transactions, assigning an objective arm's length value to a related party transaction is difficult and requires significant judgement. We have identified related party transactions at arm's-length as a key audit matter due to the judgement involved.	Schedule 5(b) by inspecting supporting documentation to determine compliance with the disclosed procurement policy and practices. **Arm's length valuation rule** We obtained Electricity Invercargill Limited's assessment of available independent and objective measures used in supporting the arm's length valuation principal and performed the following procedures: ● Re-performed the calculations within Electricity Invercargill Limited's benchmarking assessment and agreed key inputs and assumptions to supporting documentation; ● Where benchmarking or other market information was used as independent and objective measures, we assessed whether the related party transaction values fell within a reasonable range. Qualitative factors were considered in determining the appropriate acceptable range.

Directors' responsibilities

The Directors of the Company are responsible in accordance with the Determination for:

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

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

Auditor's responsibilities

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

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

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

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

Inherent limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error or non-compliance with the Determination may occur and not be detected. A reasonable assurance engagement throughout the disclosure year does not provide assurance on whether compliance with the Determination will continue in the future.

Restricted use

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

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 Electricity Distribution Services Default Price-Quality Path Determination 2020, other regulatory requirements of the Commerce Act 1986, regulatory training and advisory services, 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
31 August 2023

6. DIRECTORS' CERTIFICATE

Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Robert Datema Jamieson and Paul Michael Kiesanowski, 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, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and

b) the historical information used in the preparation of Schedules 8, 9a, 9b, 9c, 9d, 9e, 10, and 14 has been properly extracted from the 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 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.

Robert Datema Jamieson **Paul Michael Kiesanowski**

31 August 2023

Footnote:
The Directors of Electricity Invercargill Limited (EIL) note the amendment in respect to the Information Disclosure Exemption: Disclosure and auditing or reliability information within schedule 10, issued by the Commerce Commission on 26 May 2023 that has removed the auditor report requirements relating to the treatment of successive interruptions for reporting SAIDI, SAIFI, and interruptions, because of potential inconsistencies in treatment approaches across the industry.

Directors note that they do not appear to have been provided a similar exemption relating to treatment of successive interruptions regarding their certification. The information has been prepared on a basis consistent with the previous year's disclosure and Electricity Invercargill Limited has recorded successive interruptions, originating from the same cause, as single interruptions.