

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

FOR THE YEAR ENDED 31 MARCH 2025

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1. INTRODUCTION

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

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

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 2025**

SCHEDULE 1: ANALYTICAL RATIOS

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

sch ref

1(i): Expenditure metrics

	Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
Operational expenditure	25,170	364	97,782	9,701	40,782
Network	7,571	110	29,410	2,918	12,266
Non-network	17,600	255	68,372	6,783	28,516
Expenditure on assets	28,756	416	111,712	11,084	46,592
Network	28,756	416	111,712	11,084	46,592
Non-network	–	–	–	–	–

1(ii): Revenue metrics

	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
Total consumer line charge revenue	77,779	1,126
Standard consumer line charge revenue	77,779	1,126
Non-standard consumer line charge revenue	–	–

1(iii): Service intensity measures

Demand density	98	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
Volume density	385	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
Connection point density	27	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
Energy intensity	14,470	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

1(iv): Composition of regulatory income

	($000)	% of revenue
Operational expenditure	6,455	32.44%
Pass-through and recoverable costs excluding financial incentives and wash-ups	4,947	24.86%
Total depreciation	4,315	21.68%
Total revaluations	2,851	14.33%
Regulatory tax allowance	1,063	5.34%
Regulatory profit/(loss) including financial incentives and wash-ups	5,973	30.01%
Total regulatory income	19,902	

1(v): Reliability

Interruption rate	8.72	*Interruptions per 100 circuit km*

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2025**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

sch ref

2(i): Return on Investment

	CY-2	CY-1	Current Year CY
	%	%	%
ROI – comparable to a post tax WACC			
Reflecting all revenue earned	8.77%	6.22%	4.85%
Excluding revenue earned from financial incentives	8.59%	6.35%	4.84%
Excluding revenue earned from financial incentives and wash-ups	8.70%	6.45%	4.93%
Mid-point estimate of post tax WACC	4.88%	6.05%	6.18%
25th percentile estimate	4.20%	5.37%	5.50%
75th percentile estimate	5.56%	6.73%	6.86%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	9.28%	6.92%	5.57%
Excluding revenue earned from financial incentives	9.11%	7.05%	5.56%
Excluding revenue earned from financial incentives and wash-ups	9.21%	7.15%	5.65%
WACC rate used to set regulatory price path	4.57%	4.57%	4.57%
Mid-point estimate of vanilla WACC	5.39%	6.75%	6.90%
25th percentile estimate	4.71%	6.07%	6.22%
75th percentile estimate	6.07%	7.43%	7.58%

2(ii): Information Supporting the ROI

		($000)		
	Total opening RAB value	113,034		
plus	Opening deferred tax	(7,412)		
Opening RIV			105,622	
Line charge revenue			19,947	
	Expenses cash outflow	11,402		
add	Assets commissioned	7,667		
less	Asset disposals	124		
add	Tax payments	624		
less	Other regulated income	(46)		
Mid-year net cash outflows			19,616	
Term credit spread differential allowance			–	
	Total closing RAB value	119,114		
less	Adjustment resulting from asset allocation	(0)		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(7,851)		
Closing RIV			111,263	
ROI – comparable to a vanilla WACC				5.57%
	Leverage (%)			42%
	Cost of debt assumption (%)			6.12%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				4.85%

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

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

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

Year-end ROI – comparable to a vanilla WACC	5.57%
Year-end ROI – comparable to a post tax WACC	4.85%

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

2(v): Financial Incentives and Wash-Ups

IRIS incentive adjustment	33	
Purchased assets – avoided transmission charge	–	
Innovation and non-traditional solutions recovered amount	–	
Quality incentive adjustment	(18)	
Other CPP financial incentives	–	
Financial incentives		15
Impact of financial incentives on ROI		0.01%
Input methodology claw-back	–	
CPP application recoverable costs	–	
CPP Urgent project allowance	–	Not Required before DY2
Reopener event allowance	–	Not Required before DY2
Wash-up draw down amount	–	Not Required before DY2
Catastrophic event allowance	–	Not Required after DY20
Capex wash-up adjustment	(142)	Not Required after DY20
Transmission asset wash-up adjustment	–	Not Required after DY20
2013–15 NPV wash-up allowance	–	Not Required after DY20
Reconsideration event allowance	–	Not Required after DY20
Other CPP wash-ups	–	
Wash-up costs		(142)
Impact of wash-up costs on ROI		–0.10%

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2025**

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			($000)
7		**3(i): Regulatory Profit**	
8		**Income**	
9		Line charge revenue	19,947
10	*plus*	Gains / (losses) on asset disposals	(118)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	73
12			
13		**Total regulatory income**	19,902
14		**Expenses**	
15	*less*	Operational expenditure	6,455
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	4,947
18			
19		**Operating surplus / (deficit)**	8,499
20			
21	*less*	Total depreciation	4,315
22			
23	*plus*	Total revaluations	2,851
24			
25		**Regulatory profit / (loss) before tax**	7,036
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	1,063
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	5,973
32			

			($000)	
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**		
34		**Pass through costs**		
35		Electricity lines service charge payable to Transpower	–	Not Required before DY
36		Transpower new investment contract charges	–	Not Required before DY
37		System operator services	–	Not Required before DY
38		Rates	218	
39		Commerce Act levies	64	
40		Industry levies	73	
41		CPP or DPP specified pass-through costs	–	
42		**Recoverable costs excluding financial incentives and wash-ups**		
43		Independent engineer costs	–	Not Required before DY
44		FENZ levies	–	Not Required before DY
45		Electricity lines service charge payable to Transpower	4,234	Not Required after DY20
46		Transpower new investment contract charges	358	Not Required after DY20
47		System operator services	–	Not Required after DY20
48		Distributed generation allowance	–	Not Required after DY20
49		Extended reserves allowance	–	
50		Other CPP recoverable costs excluding financial incentives and wash-ups	–	
51		**Pass-through and recoverable costs excluding financial incentives and wash-ups**	4,947	
52				

			($000)
53		**3(iv): Merger and Acquisition Expenditure**	
54			
55		Merger and acquisition expenditure	–
56			
57		*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)*	

			($000)
58		**3(v): Other Disclosures**	
59			
60		Self-insurance allowance	–

Company Name: Electricity Invercargill Limited
For Year Ended: 31 March 2025

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	89,033	91,117	99,905	107,300	113,034
less	Total depreciation	3,339	3,495	3,729	4,044	4,315
plus	Total revaluations	1,353	6,303	6,645	4,309	2,851
plus	Assets commissioned	4,132	6,117	4,522	5,631	7,667
less	Asset disposals	62	137	43	163	124
plus	Lost and found assets adjustment	–	–	–	–	–
plus	Adjustment resulting from asset allocation	–	(0)	0	0	(0)
	Total closing RAB value	91,117	99,905	107,300	113,034	119,114

4(ii): Unallocated Regulatory Asset Base

			Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
	Total opening RAB value			113,034		113,034
less						
	Total depreciation			4,315		4,315
plus						
	Total revaluations			2,851		2,851
plus						
	Assets commissioned (other than below)	Not Required after DY2025	3,067		3,067	
	Assets commissioned out of WUC	Not Required before DY2026			–	
	Assets acquired (other than below)	Not Required before DY2026			–	
	Assets acquired from a regulated supplier				–	
	Assets acquired from a related party		4,600		4,600	
	Assets commissioned			7,667		7,667
less						
	Asset disposals (other than below)		124		124	
	Asset disposals to a regulated supplier				–	
	Asset disposals to a related party				–	
	Asset disposals			124		124
plus	Lost and found assets adjustment			–		–
plus	Adjustment resulting from asset allocation					(0)
	Total closing RAB value			119,114		119,114

* 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	1,299
	CPI_4-4	1,267
	Revaluation rate (%)	2.53%

		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
	Total opening RAB value	113,034		113,034	
less	Opening value of fully depreciated, disposed and lost assets	145		145	
	Total opening RAB value subject to revaluation	112,890		112,890	
	Total revaluations		2,851		2,851

4(iv): Roll Forward of Works Under Construction

			Unallocated works under construction		Allocated works under construction	
	Works under construction—preceding disclosure year	Not Required after DY2025		2,539		2,539
plus	Capital expenditure	Not Required after DY2025	7,088		7,088	
less	Assets commissioned	Not Required after DY2025	7,667		7,667	
plus	Adjustment resulting from asset allocation	Not Required after DY2025			–	
	Works under construction - current disclosure year	Not Required after DY2025		1,960		1,960

			Unallocated works under construction		Allocated works under construction	
	Works under construction—preceding disclosure year	Not Required before DY2026				
plus	WUC capital expenditure	Not Required before DY2026				
	WUC acquired from a regulated supplier	Not Required before DY2026				
	WUC acquired from a related party	Not Required before DY2026				
	WUC capital expenditure - other	Not Required before DY2026				
	Total WUC capital expenditure	Not Required before DY2026	–		–	
less	WUC capital contributions	Not Required before DY2026				
less	WUC other revenue	Not Required before DY2026				
less	Assets commissioned out of WUC	Not Required before DY2026	–		–	
plus	Adjustment resulting from asset allocation	Not Required before DY2026				
	Works under construction - current disclosure year	Not Required before DY2026		–		–
	Highest rate of capitalised finance applied					–

4(v): Regulatory Depreciation

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Depreciation - standard	4,315		4,315	
Depreciation - no standard life assets			–	
Depreciation - modified life assets			–	
Depreciation - alternative depreciation in accordance with CPP			–	
Total depreciation		4,315		4,315

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	1,471	7,843	24,374	3,138	49,411	12,459	10,741	3,596	–	113,034
less	Total depreciation	45	240	913	116	1,805	529	439	228	–	4,315
plus	Total revaluations	37	198	616	79	1,247	312	271	91	–	2,851
plus	Assets commissioned	–	253	56	873	1,749	1,033	2,937	765	–	7,667
less	Asset disposals	–	–	–	–	–	100	23	–	–	124
plus	Lost and found assets adjustment									–	–
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
plus	Asset category transfers	–	–	–	–	–	–	–	–	–	–
	Total closing RAB value	1,463	8,055	24,132	3,974	50,603	13,176	13,487	4,224	–	119,114
	Asset Life										
	Weighted average remaining asset life	32.8	38.5	33.3	38.4	35.7	27.5	27.5	17.3	–	(years)
	Weighted average expected total asset life	40.3	57.2	50.0	59.8	58.6	45.0	38.9	36.6	–	(years)

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2025**

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**			7,036
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	1,243		
13		Amortisation of revaluations	1,011		
14		**Total**			2,254
15					
16	*less*	Total revaluations	2,851		
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	7	*	
20		Notional deductible interest	2,635		
21		**Total**			5,494
22					
23		**Regulatory taxable income**			3,796
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			3,796
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			1,063
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	16,163		
37	*less*	Amortisation of initial differences in asset values	1,243		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	80		
40		Closing unamortised initial differences in asset values			14,839
41					
42		Opening weighted average remaining useful life of relevant assets (years)			13
43					

5a(iv): Amortisation of Revaluations

		($000)
Opening sum of RAB values without revaluations	87,188	
Adjusted depreciation	3,304	
Total depreciation	4,315	
Amortisation of revaluations		1,011

5a(v): Reconciliation of Tax Losses

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

5a(vi): Calculation of Deferred Tax Balance

		($000)
Opening deferred tax	(7,412)	
plus Tax effect of adjusted depreciation	925	
less Tax effect of tax depreciation	1,139	
plus Tax effect of other temporary differences*	89	
less Tax effect of amortisation of initial differences in asset values	348	
plus Deferred tax balance relating to assets acquired in the disclosure year	–	
less Deferred tax balance relating to assets disposed in the disclosure year	(34)	
plus Deferred tax cost allocation adjustment	0	
Closing deferred tax		(7,851)

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	46,138	
less Tax depreciation	4,067	
plus Regulatory tax asset value of assets commissioned	8,155	
less Regulatory tax asset value of asset disposals	1	
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		50,224

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2025**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref

5b(i): Summary—Related Party Transactions

	($000)	($000)
Total regulatory income		–
Market value of asset disposals		–
Service interruptions and emergencies	434	
Vegetation management	2	
Routine and corrective maintenance and inspection	862	
Asset replacement and renewal (opex)	93	
Network opex		1,391
Business support	1,480	
System operations and network support	494	
Non-network solutions provided by a related party or third party	–	
Operational expenditure		3,365
Consumer connection	506	
System growth	–	
Asset replacement and renewal (capex)	2,267	
Asset relocations	27	
Quality of supply	219	
Legislative and regulatory	–	
Other reliability, safety and environment	1,406	
Expenditure on non-network assets		–
Expenditure on assets		4,425
Cost of financing		–
Value of capital contributions		–
Value of vested assets		–
Capital Expenditure		4,425
Total expenditure		7,791
Other related party transactions		198

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

Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
PowerNet Limited	Service interruptions and emergencies	434
PowerNet Limited	Vegetation management	2
PowerNet Limited	Routine and corrective maintenance and inspection	862
PowerNet Limited	Asset replacement and renewal (opex)	93
PowerNet Limited	System operations and network support	494
PowerNet Limited	Business support	1,176
Invercargill City Holdings	Business support	155
PowerNet Limited	Consumer connection	506
PowerNet Limited	Asset replacement and renewal (capex)	2,267
PowerNet Limited	Quality of supply	219
PowerNet Limited	Other reliability, safety and environment	1,406
PowerNet Limited	Asset relocations	27
Directors	Business support	149
Total value of related party transactions		7,791

** include additional rows if needed*

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2025

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

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

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
** include additional rows if needed*						–	–	–

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

Gross term credit spread differential		–
Total book value of interest bearing debt		
Leverage	42%	
Average opening and closing RAB values		
Attribution Rate (%)		–
Term credit spread differential allowance		–

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2025

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		568			
Not directly attributable				–	
Total attributable to regulated service		568			
Vegetation management					
Directly attributable		2			
Not directly attributable				–	
Total attributable to regulated service		2			
Routine and corrective maintenance and inspection					
Directly attributable		1,252			
Not directly attributable				–	
Total attributable to regulated service		1,252			
Asset replacement and renewal					
Directly attributable		119			
Not directly attributable				–	
Total attributable to regulated service		119			
Non-network solutions provided by a related party or third party					
Directly attributable		–			
Not directly attributable				–	
Total attributable to regulated service		–			
System operations and network support					
Directly attributable		1,734			
Not directly attributable		–		–	
Total attributable to regulated service		1,734			
Business support					
Directly attributable		2,190			
Not directly attributable		589		589	
Total attributable to regulated service		2,779			
Operating costs directly attributable		5,866			
Operating costs not directly attributable	–	589	–	589	–
Operational expenditure		6,455			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	($000)
Pass through costs	
Directly attributable	355
Not directly attributable	–
Total attributable to regulated service	355
Recoverable costs	
Directly attributable	4,592
Not directly attributable	–
Total attributable to regulated service	4,592

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

			($000)	
Change in cost allocation 1			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				

			($000)	
Change in cost allocation 2			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				

			($000)	
Change in cost allocation 3			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 2025

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	1,463
Not directly attributable	–
Total attributable to regulated service	1,463
Subtransmission cables	
Directly attributable	8,055
Not directly attributable	–
Total attributable to regulated service	8,055
Zone substations	
Directly attributable	24,132
Not directly attributable	–
Total attributable to regulated service	24,132
Distribution and LV lines	
Directly attributable	3,974
Not directly attributable	–
Total attributable to regulated service	3,974
Distribution and LV cables	
Directly attributable	50,603
Not directly attributable	–
Total attributable to regulated service	50,603
Distribution substations and transformers	
Directly attributable	13,176
Not directly attributable	–
Total attributable to regulated service	13,176
Distribution switchgear	
Directly attributable	13,487
Not directly attributable	–
Total attributable to regulated service	13,487
Other network assets	
Directly attributable	4,224
Not directly attributable	–
Total attributable to regulated service	4,224
Non-network assets	
Directly attributable	–
Not directly attributable	–
Total attributable to regulated service	–
Regulated service asset value directly attributable	119,114
Regulated service asset value not directly attributable	–
Total closing RAB value	119,114

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

Change in asset value allocation 1

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

Change in asset value allocation 2

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

Change in asset value allocation 3

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

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

Company Name: Electricity Invercargill Limited
For Year Ended: 31 March 2025

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

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

sch ref	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
	Service interruptions and emergencies										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Vegetation management										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Routine and corrective maintenance and inspection										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Asset replacement and renewal										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Non-network solutions provided by a related party or third party *Not required before DY2025*										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	System operations and network support										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Business support										
	Administration Expenses	ABAA	Revenue	Proxy	93.66%	6.34%	-	589	40	629	
										-	
										-	
										-	
	Not directly attributable						-	589	40	629	-
	Operating costs not directly attributable						-	589	40	629	-
	Pass through and recoverable costs										
	Pass through costs										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Recoverable costs										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	** include additional rows if needed*										

Company Name: Electricity Invercargill Limited
For Year Ended: 31 March 2025

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

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

sch ref	Line item*	Allocation methodology type	Allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
	Subtransmission lines										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Subtransmission cables										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Zone substations										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Distribution and LV lines										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Distribution and LV cables										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Distribution substations and transformers										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Distribution switchgear										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Other network assets										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Non-network assets										
										-	
										-	
										-	
										-	
	Not directly attributable						-	-	-	-	-
	Regulated service asset value not directly attributable						-	-	-	-	-

* include additional rows if needed

Company Name: Electricity Invercargill Limited
For Year Ended: 31 March 2025

SCHEDULE 5h: REPORT ON CYBERSECURITY EXPENDITURE

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

sch ref

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

Cybersecurity (Commission only)	–

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

Cybersecurity (Commission only)	6

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

	Target ($000)	Actual ($000)	% variance
Cybersecurity (Commission only)	–	6	–

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2025**

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

6a(i): Expenditure on Assets

			($000)	($000)
8		Consumer connection		787
9		System growth		–
10		Asset replacement and renewal		4,196
11		Asset relocations		67
12		Reliability, safety and environment:		
13		Quality of supply	275	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	2,050	
16		**Total reliability, safety and environment**		2,325
17		**Expenditure on network assets**		7,375
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		7,375
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		287
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		7,088

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	–

6a(iii): Consumer Connection

		*Consumer types defined by EDB**	($000)	($000)
33		Customer Connections < 20 kVA	84	
34		Customer Connections 21 - 99 kVA	27	
35		Customer Connections > 100 kVA	320	
36		New Subdivisions	355	
37				
38		** include additional rows if needed*		
39		**Consumer connection expenditure**		787
40				
41	*less*	Capital contributions funding consumer connection expenditure	252	
42		**Consumer connection less capital contributions**		534

6a(iv): System Growth and Asset Replacement and Renewal

			System Growth ($000)	Asset Replacement and Renewal ($000)
46		Subtransmission	–	–
47		Zone substations	–	37
48		Distribution and LV lines	–	163
49		Distribution and LV cables	–	1,280
50		Distribution substations and transformers	–	859
51		Distribution switchgear	–	1,857
52		Other network assets	–	–
53		**System growth and asset replacement and renewal expenditure**	–	4,196
54	*less*	Capital contributions funding system growth and asset replacement and renewal	–	–
55		**System growth and asset replacement and renewal less capital contributions**	–	4,196

6a(v): Asset Relocations

		*Project or programme**	($000)	($000)
59				
60				
61				
62				
63				
64		** include additional rows if needed*		
65		All other projects or programmes - asset relocations	67	
66		**Asset relocations expenditure**		67
67	*less*	Capital contributions funding asset relocations	35	
68		**Asset relocations less capital contributions**		32

6a(vi): Quality of Supply

	Project or programme*	($000)	($000)
	Fault Indicator Project	190	
	Network Automation Projects	85	
	* include additional rows if needed		
	All other projects programmes - quality of supply	–	
	Quality of supply expenditure		275
less	Capital contributions funding quality of supply	–	
	Quality of supply less capital contributions		275

6a(vii): Legislative and Regulatory

	Project or programme*	($000)	($000)
	* include additional rows if needed		
	All other projects or programmes - legislative and regulatory	–	
	Legislative and regulatory expenditure		–
less	Capital contributions funding legislative and regulatory	–	
	Legislative and regulatory less capital contributions		–

6a(viii): Other Reliability, Safety and Environment

	Project or programme*	($000)	($000)
	Earth Upgrades - City	784	
	Pillar Box Lid Upgrade	154	
	Fibre Installation	602	
	LV Tie Point Disconnectors	257	
	Oil-Filled Cable Work	253	
	* include additional rows if needed		
	All other projects or programmes - other reliability, safety and environment	–	
	Other reliability, safety and environment expenditure		2,050
less	Capital contributions funding other reliability, safety and environment	–	
	Other reliability, safety and environment less capital contributions		2,050

6a(ix): Non-Network Assets

Routine expenditure

	Project or programme*	($000)	($000)
	* include additional rows if needed		
	All other projects or programmes - routine expenditure	–	
	Routine expenditure		–

Atypical expenditure

	Project or programme*	($000)	($000)
	* include additional rows if needed		
	All other projects or programmes - atypical expenditure	–	
	Atypical expenditure		–
	Expenditure on non-network assets		–

			Company Name	**Electricity Invercargill Limited**
			For Year Ended	**31 March 2025**

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

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

sch ref			($000)	($000)
7	**6b(i): Operational Expenditure** *Required for DY2025 only*			
8	Service interruptions and emergencies		568	
9	Vegetation management		2	
10	Routine and corrective maintenance and inspection		1,252	
11	Asset replacement and renewal		119	
12	**Network opex**			1,942
13	Non-network solutions provided by a related party or third party	*Required for DY2025 only*	–	
14	System operations and network support		1,734	
15	Business support		2,779	
16	**Non-network opex**			4,514
17				
18	**Operational expenditure**			6,455
19	**6b(i): Operational Expenditure** *Not Required before DY2026*		($000)	($000)
20	Service interruptions and emergencies:			
21	Vegetation-related			
22	Other			
23	**Total service interruptions and emergencies**		–	
24	Vegetation management:			
25	Assessment and notification costs			
26	Felling or trimming vegetation - in-zone			
27	Felling or trimming vegetation - out-of-zone			
28	Other			
29	**Total vegetation management**		–	
30				
31	Routine and corrective maintenance and inspection:			
32	Asset replacement and renewal			
33	**Network opex**			–
34	Non-network solutions provided by a related party or third party			
35	System operations and network support			
36	Business support			
37	**Non-network opex**			–
38				
39	**Operational expenditure**			–
40	**6b(ii): Subcomponents of Operational Expenditure (where known)**			
41	Energy efficiency and demand side management, reduction of energy losses			230
42	Direct billing*			–
43	Research and development			–
44	Insurance			225
45	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*			

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2025**

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	19,658	19,947	1%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	1,344	787	(41%)
11	System growth	–	–	–
12	Asset replacement and renewal	4,205	4,196	(0%)
13	Asset relocations	7	67	832%
14	Reliability, safety and environment:			
15	Quality of supply	170	275	62%
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	1,397	2,050	47%
18	**Total reliability, safety and environment**	1,567	2,325	48%
19	**Expenditure on network assets**	7,123	7,375	4%
20	Expenditure on non-network assets		–	–
21	Expenditure on assets	7,123	7,375	4%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	615	568	(8%)
24	Vegetation management	3	2	(16%)
25	Routine and corrective maintenance and inspection	1,791	1,252	(30%)
26	Asset replacement and renewal	189	119	(37%)
27	**Network opex**	2,597	1,942	(25%)
28	Non-network solutions provided by a related party or third party	–	–	–
29	System operations and network support	1,809	1,734	(4%)
30	Business support	2,441	2,779	14%
31	**Non-network opex**	4,250	4,514	6%
32	**Operational expenditure**	6,847	6,455	(6%)
33	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
34	Energy efficiency and demand side management, reduction of energy losses	–	–	–
35	Overhead to underground conversion	–	–	–
36	Research and development	–	–	–
37				
38	**7(v): Subcomponents of Operational Expenditure (where known)**			
39	Energy efficiency and demand side management, reduction of energy losses	–	230	–
40	Direct billing	–	–	–
41	Research and development	–	–	–
42	Insurance	501	225	(55%)
43				

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

45 *2 From the CY+1 nominal dollar expenditure forecasts disclosed in accordance with clause 2.6.6 for the forecast period starting at the beginning of the disclosure year (the second to last disclosure of Schedules 11a and 11b)*

Company Name
For Year Ended
Network / Sub-Network Name

Company Name: Electricity Invercargill Limited
For Year Ended: 31 March 2025
Network / Sub-Network Name:

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

This schedule requires the billed quantities and associated line charge revenues for each price category code used by the EDB in its pricing schedules. Information is also required on the number of ICPs that are included in each consumer group or price category code, and the energy delivered to these ICPs.
EDBs should feel free to adjust the page break of this schedule to assist with readibility if needed.

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
Low user	Residential	Standard	6,493	42,056
Residential	Residential	Standard	9,130	91,023
General	Commercial	Standard	1,950	48,056
Individual Non Half Hour	Commercial	Standard	29	3,697
Individual Half Hour	Industrial	Standard	141	71,629	
Add extra rows for additional consumer groups or price category codes as necessary				
		Standard consumer totals	17,723	256,460
		Non-standard consumer totals	-	-
		Total for all consumers	17,723	256,460

Billed quantities by price component

Standardised price component	Daily fixed charge - $/day		All-inclusive TOU peak charge - $/kWh		All-inclusive TOU shoulder charge - $/kWh		All-inclusive TOU off-peak charge - $/kWh		Individual contract - $/kWh		Individual contract - $/day		
EDB defined price component			Purchases Peak Volume at GXP		Purchases Shoulder Volume at GXP		Purchases Night Volume at GXP		Sales Day Volume at Customer Meter				
	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Distribution billed quantity	Transmission billed quantity	Add extra columns for additional billed quantities by price component as necessary
	2,371,022	2,371,022	17,608,441	17,608,441	15,494,793	15,494,793	10,732,441	10,732,441					
	3,336,900	3,336,900	38,209,111	38,209,111	34,034,901	34,034,901	23,994,533	23,994,533					
	704,781	704,781	20,156,338	20,156,338	17,885,723	17,885,723	12,540,295	12,540,295					
			1,550,488	1,550,488	1,375,825	1,375,825	964,688	964,688			9,931	9,955	
									51,216,232	51,216,232	52,275	52,275	
	6,412,703	6,412,703	77,524,377	77,524,377	68,791,243	68,791,243	48,231,905	48,231,905	51,216,232	51,216,232	62,191	62,191	
	-	-	-	-	-	-	-	-	-	-	-	-	
	6,412,703	6,412,703	77,524,377	77,524,377	68,791,243	68,791,243	48,231,905	48,231,905	51,216,232	51,216,232	62,191	62,191	

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

Consumer discounts ($000)

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Standardised price component	[Select one]			Total distribution line charge revenue	Total transmission line charge revenue
				EDB-defined price component					
					Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)		
Low user	Residential	Standard	$4,017				-	$3,114	$803
Residential	Residential	Standard	$7,850				-	$6,445	$1,405
General	Commercial	Standard	$4,487				-	$3,486	$991
Individual Non Half hour	Commercial	Standard	$282				-	$176	$106
Individual Half Hour	Industrial	Standard	$3,311				-	$2,173	$1,138
			-				-	-	-
			-				-	-	-
			-				-	-	-
			-				-	-	-
			-				-	-	-

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

Standard consumer totals	$19,947	-	-	-	$15,355	$4,592
Non-standard consumer totals	-	-	-	-	-	-
Total for all consumers	$19,947	-	-	-	$15,355	$4,592

Line charge revenues ($000) by price component

Consumer group name or price category code	Standardised connection types	Standard or non-standard consumer group (specify)	Standardised price component	Daily fixed charge - $/day			All-inclusive TOU peak charge - $/kWh			All-inclusive TOU shoulder charge - $/kWh			All-inclusive TOU off-peak charge - $/kWh			Individual contract - $/kWh			Individual contract - $/day			Add extra columns for additional line charge revenues by price component as necessary
			EDB-defined price component				Purchases Peak Volume at GXP			Purchases Shoulder Volume at GXP			Purchases Night Volume at GXP			Sales Day Volume at Customer Meter						
				Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	Distribution line charge revenue	Transmission line charge revenue	Total line charge revenue (distribution and transmission)	
Low user	Residential	Standard		$821	$960	$1,225	$1,620	-	$1,620	$1,081	-	$1,081	$207	-	$207			-			-	
Residential	Residential	Standard		$1,844	$1,405	$3,249	$2,542	-	$2,542	$1,819	-	$1,819	$240	-	$240			-			-	
General	Commercial	Standard		$1,877	$991	$2,068	$1,318	-	$1,318	$954	-	$954	$125	-	$125			-			-	
Individual Non Half hour	Commercial	Standard				-	$75	$28	$103	$43	$15	$74	$10	-	$10			-	$43	$53	$96	
Individual Half Hour	Industrial	Standard				-			-			-			-	$1,169	$97	$1,265	$954	$1,091	$2,045	
						-			-			-			-			-			-	
						-			-			-			-			-			-	
						-			-			-			-			-			-	
						-			-			-			-			-			-	
						-			-			-			-			-			-	
Standard consumer totals				$3,242	$3,299	$6,541	$5,575	$28	$5,603	$3,889	$25	$3,914	$482	-	$482	$1,169	$97	$1,265	$997	$1,144	$2,141	
Non-standard consumer totals				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Total for all consumers				$3,242	$3,299	$6,541	$5,575	$28	$5,603	$3,889	$25	$3,914	$482	-	$482	$1,169	$97	$1,265	$997	$1,144	$2,141	

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 2025**
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref

9a: Asset Register

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	751	759	8	3
10	All	Overhead Line	Wood poles	No.	192	185	(7)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	1	1	–	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	15	15	–	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	12	12	0	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	5	5	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	N/A
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	7	7	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	6	6	–	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	8	8	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	N/A
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	53	53	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	N/A
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	7	7	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	22	21	(1)	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	67	68	1	3
39	HV	Distribution Cable	Distribution UG PILC	km	93	92	(1)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	2	2	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	75	–	(75)	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	62	63	1	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	450	306	(144)	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	11	9	(2)	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	439	441	2	4
48	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	N/A
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	38	35	(3)	4
50	LV	LV Line	LV OH Conductor	km	30	30	0	3
51	LV	LV Cable	LV UG Cable	km	425	426	2	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	170	171	0	2
53	LV	Connections	OH/UG consumer service connections	No.	18,039	18,109	70	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	177	129	(48)	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 2025
Network / Sub-network Name:

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

9b: Asset Age Profile

Disclosure Year (year ended):

Number of assets at disclosure year end by installation date

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)
All	Overhead Line	Concrete poles / steel structure	No.	–	–	–	307	6	–	1	2	4	2	–	6	3	4	2	11	5	26	97	34	74	17	23	28	30	8	8	7	9	10	11	13	6	6	759		3
All	Overhead Line	Wood poles	No.	–	–	–	134	1	–	2	11	11	4	6	6	4	2	1	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	1	185		3
All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	–	0	–	–	1	0	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	0	1		4
HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	5	1	4	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	5	–	–	–	–	–	0	0	–	0	–	–	15		4
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	5	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	12		4
HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	1	1	1	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	5		4
HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	–	–	–	7		4
HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	–	1	–	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	3	–	–	–	–	–	–	–	–	–	–	6		4
HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	–	–	–	8		4
HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	11	11	–	3	–	–	1	–	–	–	–	–	–	–	–	–	–	–	1	18	–	–	–	–	5	3	–	–	–	–	53		4
HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	1	2	1	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	7		4
HV	Distribution Line	Distribution OH Open Wire Conductor	km	–	–	0	11	4	2	3	1	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	1	0	–	–	–	0	–	–	–	–	0	21		3
HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	0	1	1	2	4	8	6	1	2	3	1	4	2	4	2	2	1	2	0	5	3	1	1	2	1	1	2	1	1	0	4	68		3
HV	Distribution Cable	Distribution UG PILC	km	0	–	–	13	22	32	18	3	2	–	0	0	1	–	0	2	–	–	–	0	–	–	0	–	0	–	–	1	–	–	0	–	–	–	0	92		3
HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	2		4
HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	1	7	1	2	–	–	1	1	1	–	–	1	–	1	1	1	1	3	–	3	–	4	3	3	4	1	5	10	–	3	1	–	6	63		3
HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	4	33	56	36	6	10	9	4	6	8	5	11	16	9	6	9	3	4	2	8	2	5	3	6	5	5	12	8	8	9	–	306		4
HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	1	2	1	–	–	–	–	1	–	–	–	1	–	1	1	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	9		4
HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	4	25	27	57	62	7	11	12	9	8	15	11	7	10	13	14	19	10	10	14	13	9	10	5	14	5	7	2	12	12	1	–	441		4
HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	1	8	1	12	5	1	1	–	1	–	–	1	1	–	–	–	2	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	35		4
LV	LV Line	LV OH Conductor	km	–	–	0	4	0	1	1	15	–	2	1	0	0	0	–	0	–	–	0	0	0	0	0	1	0	0	0	0	0	0	0	1	0	0	30		3
LV	LV Cable	LV UG Cable	km	1	–	9	46	72	110	65	12	15	21	3	10	6	9	4	7	6	3	3	2	1	1	2	3	4	2	2	0	1	1	1	1	0	2	426		3
LV	LV Street lighting	LV OH/UG Streetlight circuit	km	2	0	1	14	4	22	88	19	2	1	0	0	1	1	1	2	1	1	1	0	2	1	3	1	0	0	0	0	1	0	1	1	0	3	171		2
LV	Connections	OH/UG consumer service connections	No.	–	3	114	2,215	3,954	3,572	5,435	40	54	60	196	257	277	197	211	120	99	93	97	83	57	63	73	84	62	53	67	70	116	91	129	148	19	–	18,109		4
All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	3	31	30	1	4	–	–	1	–	–	–	–	–	–	–	–	–	–	1	22	5	–	2	5	10	10	–	–	1	–	3	129		4
All	SCADA and communications	SCADA and communications equipment operating as a single syster	Lot	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		4
All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
All	Load Control	Centralised plant	Lot	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		4
All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2025**
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

9c: Overhead Lines and Underground Cables

	Overhead (km)	Underground (km)	Total circuit length (km)
Circuit length by operating voltage (at year end)			
> 66kV	–	–	–
50kV & 66kV	–	–	–
33kV	1	27	28
SWER (all SWER voltages)	–	–	–
22kV (other than SWER)	–	–	–
6.6kV to 11kV (inclusive—other than SWER)	21	160	181
Low voltage (< 1kV)	30	426	456
Total circuit length (for supply)	52	613	665
Dedicated street lighting circuit length (km)	25	146	171
Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–

Overhead circuit length by terrain (at year end)	Circuit length (km)	(% of total overhead length)
Urban	49	93%
Rural	2	3%
Remote only	–	–
Rugged only	2	4%
Remote and rugged	–	–
Unallocated overhead lines	–	–
Total overhead length	52	100%

	Circuit length (km)	(% of total circuit length)
Length of circuit within 10km of coastline or geothermal areas (where known)	665	100%

	Circuit length (km)	(% of total overhead length)	
Overhead circuit requiring vegetation management	4	8%	*Not required after DY2025*

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

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

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

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

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2025**

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 2025**
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

9e(i): Consumer Connections and Decommissionings

Number of ICPs connected during year by consumer type

	*Consumer types defined by EDB**	Number of connections (ICPs)
Residential		104
Individual Half Hour		5
Low User		3
General		49

** include additional rows if needed*

Connections total 161

Number of ICPs decommissioned during year by consumer type

	*Consumer types defined by EDB**	Number of decommissionings
Low User		3
Residential		14
Commercial		34
Industrial		1

** include additional rows if needed*

Decommissionings total 52

Distributed generation

Number of connections made in year	30	connections
Capacity of distributed generation installed in year	0.30	MVA

9e(ii): System Demand

		Demand at time of maximum coincident demand (MW)	
	Maximum coincident system demand		
	GXP demand	65	
plus	Distributed generation output at HV and above	–	
	Maximum coincident system demand	65	
less	Net transfers to (from) other EDBs at HV and above	(1)	
	Demand on system for supply to consumers' connection points	66	

		Energy (GWh)	
	Electricity volumes carried		
	Electricity supplied from GXPs	255	
less	Electricity exports to GXPs		
plus	Electricity supplied from distributed generation	0.534	
less	Net electricity supplied to (from) other EDBs	(14)	
	Electricity entering system for supply to consumers' connection points	269	
less	Total energy delivered to ICPs	256	
	Electricity losses (loss ratio)	13	4.7%

Load factor 0.47

9e(iii): Transformer Capacity

	(MVA)
Distribution transformer capacity (EDB owned)	158
Distribution transformer capacity (Non-EDB owned)	2
Total distribution transformer capacity	160

	(MVA)
Zone substation transformer capacity (EDB owned)	187
Zone substation transformer capacity (Non-EDB owned)	–
Total zone substation transformer capacity	187

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2025
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(i): Interruptions

Interruptions by class	Number of interruptions
Class A (planned interruptions by Transpower)	–
Class B (planned interruptions on the network)	30
Class C (unplanned interruptions on the network)	25
Class D (unplanned interruptions by Transpower)	–
Class E (unplanned interruptions of EDB owned generation)	–
Class F (unplanned interruptions of generation owned by others)	–
Class G (unplanned interruptions caused by another disclosing entity)	2
Class H (planned interruptions caused by another disclosing entity)	1
Class I (interruptions caused by parties not included above)	–
Total	58

Interruption restoration	≤3Hrs	>3hrs
Class C interruptions restored within	14	11

SAIFI and SAIDI by class	SAIFI	SAIDI
Class A (planned interruptions by Transpower)	–	–
Class B (planned interruptions on the network)	0.0923	25.75
Class C (unplanned interruptions on the network)	0.3472	21.00
Class D (unplanned interruptions by Transpower)	–	–
Class E (unplanned interruptions of EDB owned generation)	–	–
Class F (unplanned interruptions of generation owned by others)	–	–
Class G (unplanned interruptions caused by another disclosing entity)	0.2157	9.27
Class H (planned interruptions caused by another disclosing entity)	0.0001	0.01
Class I (interruptions caused by parties not included above)	–	–
Total	0.6553	56.04

Transitional SAIFI and SAIDI (previous method)	SAIFI	SAIDI
Class B (planned interruptions on the network)	0.0923	25.75
Class C (unplanned interruptions on the network)	0.3458	21.00

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

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

Cause	SAIFI	SAIDI
Lightning	–	–
Vegetation	–	–
Adverse weather	0.0002	0.00
Adverse environment	–	–
Third party interference	0.1096	6.67
Wildlife	–	–
Human error	–	–
Defective equipment	0.1757	10.94
Other cause	0.0134	1.09
Unknown	0.0484	2.30

Breakdown of third party interference	SAIFI	SAIDI
Dig-in	–	–
Overhead contact	–	–
Vandalism	–	–
Vehicle damage	0.0890	6.03
Other	0.0205	0.64

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

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.0165	4.51
Distribution cables (excluding LV)	0.0025	0.01
Distribution other (excluding LV)	0.0734	21.23

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	–	–
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.2208	14.13
Distribution cables (excluding LV)	0.0772	3.61
Distribution other (excluding LV)	0.0492	3.26

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	–	1	–
Subtransmission cables	–	27	–
Subtransmission other	–		
Distribution lines (excluding LV)	13	21	61.76
Distribution cables (excluding LV)	5	160	3.13
Distribution other (excluding LV)	7		
Total	25		

pwc

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2025**
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

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

SAIDI

Rank	Feeder name	Unplanned SAIDI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruption	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	BFE 1 - Ocean Beach	9.11	8	Defective Equipment	12	853	
2	LEV 11 - Leven St 11	3.05	2	Third Party Interference - Veh	7	680	
3	SPY 11 - Spey St 11	2.77	1	Defective Equipment	7	1356	
4	SOU 9 - Southern 9	2.39	1	Third Party Interference - Veh	5	689	

† *Extend table as necessary to disclose all worst-performing feeders*

SAIFI

Rank	Feeder name	Unplanned SAIFI values	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruption	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	BFE 1 - Ocean Beach	0.15	8	Defective Equipment	12	853	
2	SPY 11 - Spey St 11	0.08	1	Defective Equipment	7	1356	
3	SOU 9 - Southern 9	0.04	1	Third Party Interference - Veh	5	689	
4	LEV 11 - Leven St 11	0.04	2	Third Party Interference - Veh	7	680	

† *Extend table as necessary to disclose all worst-performing feeders*

Customer Impact

Rank	Feeder name	Customer Impact Ratio	Number of Unplanned Interruptions	Most Common Cause of Unplanned Interruption	Circuit Length of Feeder	Number of ICPs	% of Feeder Overhead (optional)
1	BFE 1 - Ocean Beach	189.26	8	Defective Equipment	12	853	
2	BFE 2 - Ocean Beach	184.11	4	Other Cause	6	195	
3	LEV 13 - Leven St 13	115.18	2	Third Party Interference - Veh	12	210	
4	LEV 11 - Leven St 11	79.46	2	Third Party Interference - Veh	7	680	

† *Extend table as necessary to disclose all worst-performing feeders*

Company Name: Electricity Invercargill Limited
For Year Ended: 31 March 2025

SCHEDULE 10a: REPORT ON INTERRUPTIONS

This schedule requires raw interruption data for the disclosure year. SAIDI and SAIFI is to be recorded using the multi-count approach.Where multiple feeders are affected, the interruption record is to be split into multiple interruptions, ie, one interruption record per feeder. This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

10a(i): Raw interruption data

Interruption identifier	Circuit location	Sub-network (where applicable)	Feeder(s) affected by interruption[1]	Start date (dd/mm/yy)	Start time (hh:mm:ss)	End date (dd/mm/yy)	End time (hh:mm:ss)	SAIDI value	SAIFI value	Number of ICPs interrupted	ICP interruption minutes	Planned or unplanned interruption (Class B or C)	Cause	Any explanation to help clarify the context of the interruption, including what the cause is if recorded as 'Other cause'
94236-94236	113/2 Lewis E Of Dee (2)	ELIN	Leven St 12 LEV 12	2024/04/08	23:04	2024/04/08	23:10	0.01	0.00	44	6	Planned	Planned interruption	Upgrade - Cable testing
94083-94083	371/3 Tay W Of Stuart (3)	ELIN	Racecourse Rd 8 RRD 8	2024/04/09	09:32	2024/04/09	13:22	0.01	0.00	1	230	Unplanned	Other cause	Upgrade - Safety isolation - LV Board alterations & New LV fuse installation
94139-94139	Spey St 8	ELIN	Spey St 8 SPY 8	2024/04/16	08:00	2024/04/16	14:51	2.46	0.01	106	411	Planned	Planned interruption	Ring main unit maintenance - Service Ring main unit
94300-94300	869/1 Forfar Cres Reserve	ELIN	Racecourse Rd 6 RRD 6	2024/05/07	08:31	2024/05/07	14:00	1.00	0.00	54	329	Planned	Planned interruption	Upgrade - Replace Transformer LV board
94303-94303	358/2 Inglewood N Of Otepuni	ELIN	Southern 8 SOU 8	2024/05/07	08:54	2024/05/07	11:09	1.29	0.01	169	135	Planned	Planned interruption	Upgrade - Ring main unit maintenance
94317-94317	357/4 Otepuni At Lindisfarne	ELIN	Southern 9 SOU 9	2024/05/08	19:31	2024/05/09	03:01	0.51	0.00	20	450	Planned	Planned interruption	Upgrade - Ring main unit maintenance
94317-94318	835/2 Prospect W Of Inglewood	ELIN	Southern 8 SOU 8	2024/05/08	19:32	2024/05/09	03:04	0.59	0.00	23	452	Planned	Planned interruption	Upgrade - Replace poles & wires
94334-94334	533/2 Tay E Of Jed	ELIN	Spey St 14 SPY 14	2024/05/12	23:00	2024/05/13	03:16	0.30	0.00	21	256	Planned	Planned interruption	Upgrade - Ring main unit maintenance
94469-94469	Leven St 11	ELIN	Leven St 11 LEV 11	2024/05/22	09:21	2024/05/22	11:52	0.01	0.00	1	151	Unplanned	Other cause	Upgrade - Remove transformer
94567-94567	305/3 Yarrow W Of Adamson	ELIN	Spey St 11 SPY 11	2024/06/05	08:02	2024/06/05	13:45	1.41	0.00	73	343	Planned	Planned interruption	Service ring main unit - Ring main unit maintenance
94567-94567	305/4 Yarrow W Of Adamson	ELIN	Spey St 11 SPY 11	2024/06/05	08:02	2024/06/05	13:50	1.98	0.01	101	348	Planned	Planned interruption	Service ring main unit - Ring main unit maintenance
94602-94602	320/3 Yarrow Opp Lithgow St	ELIN	Racecourse Rd 8 RRD 8	2024/06/09	07:00	2024/06/09	09:46	0.52	0.00	55	166	Planned	Planned interruption	Service ring main unit - Ring main unit maintenance
94631-94631	445/2 Bute St (2)	ELIN	Leven St 13 LEV 13	2024/06/12	20:00	2024/06/13	00:36	0.59	0.00	38	276	Planned	Planned interruption	Upgrade - Remove redundant transformer
94689-94689	358/2 Inglewood N Of Otepuni	ELIN	Southern 8 SOU 8	2024/06/18	08:23	2024/06/18	14:53	3.74	0.01	170	390	Planned	Planned interruption	Serive ring main unit - Ring main unit maintenance
94704-94704	Do 123951	ELIN	Ocean Beach BFE 2	2024/06/19	08:09	2024/06/19	15:30	0.85	0.00	34	441	Planned	Planned interruption	New connection - New transformer
94706-94706	Leven St 7	ELIN	Leven St 7 LEV 7	2024/06/19	17:53	2024/06/19	21:37	0.05	0.00	4	224	Planned	Planned interruption	Service ring main unit - Ring main unit maintenance
94731-94731	501/2 Kmart Forth St (2)	ELIN	Spey St 9 SPY 9	2024/06/23	07:32	2024/06/23	10:53	0.06	0.00	5	201	Planned	Planned interruption	Service ring main unit - Ring main unit maintenance
94742-94742	250/2 Earn East Of Conon(2)	ELIN	Leven St 11 LEV 11	2024/06/25	08:17	2024/06/25	11:32	0.92	0.00	84	195	Planned	Planned interruption	Service ring main unit - Ring main unit maintenance
94750-94750	967 Liffey S Of Bann	ELIN	Bluff Borough BFE 1	2024/06/26	09:45	2024/06/26	11:16	0.36	0.00	70	91	Unplanned	Unknown	Unknown - CB Tripped
94750-94750	Shannon St S Of Gore St	ELIN	Bluff Borough BFE 1	2024/06/26	09:45	2024/06/26	11:00	0.85	0.01	200	75	Unplanned	Unknown	Unknown - CB Tripped
94750-94750	Bann St Cb Bann St Cb	ELIN	Bluff Borough BFE 1	2024/06/26	09:45	2024/06/26	09:53	0.17	0.02	366	8	Unplanned	Unknown	Unknown - CB Tripped
94750-94750	962 Bann E Of Liffey 962	ELIN	Bluff Borough BFE 1	2024/06/26	09:45	2024/06/26	11:27	0.66	0.01	114	102	Unplanned	Unknown	Unknown - CB Tripped
94750-94750	Bluff Borough	ELIN	Bluff Borough BFE 1	2024/06/26	09:45	2024/06/26	10:45	0.07	0.00	22	60	Unplanned	Unknown	Unknown - CB Tripped
94750-94750	961 Bann W Of Liffey	ELIN	Bluff Borough BFE 1	2024/06/26	09:45	2024/06/26	11:14	0.15	0.00	29	89	Unplanned	Unknown	Unknown - CB Tripped
94750-94750	929/1 Suir N Of Ocean Beach	ELIN	Bluff Borough BFE 1	2024/06/26	09:45	2024/06/26	09:53	0.03	0.00	54	10	Unplanned	Unknown	Unknown - CB Tripped
94768-94768	929/1 Suir N Of Ocean Beach	ELIN	Bluff Borough BFE 1	2024/06/27	18:32	2024/06/27	18:47	0.05	0.00	55	15	Unplanned	Defective equipment	Deterioration - Failed insulator
94768-94768	Bluff Borough	ELIN	Bluff Borough BFE 1	2024/06/27	18:32	2024/06/27	22:13	0.29	0.00	23	221	Unplanned	Defective equipment	Deterioration - Failed insulator
94768-94768	Bluff Borough	ELIN	Bluff Borough BFE 1	2024/06/27	18:32	2024/06/27	19:52	0.10	0.00	22	80	Unplanned	Defective equipment	Deterioration - Failed insulator
94768-94768	961 Bann W Of Liffey	ELIN	Bluff Borough BFE 1	2024/06/27	18:32	2024/06/27	20:20	1.28	0.01	210	108	Unplanned	Defective equipment	Deterioration - Failed insulator
94768-94768	Shannon St S Of Gore St	ELIN	Bluff Borough BFE 1	2024/06/27	18:32	2024/06/27	20:54	1.39	0.01	174	142	Unplanned	Defective equipment	Deterioration - Failed insulator
94768-94768	Bluff Borough	ELIN	Bluff Borough BFE 1	2024/06/27	20:17	2024/06/27	20:19	0.00	0.00	22	2	Unplanned	Defective equipment	Deterioration - Failed insulator
94805-94805	490/2 Pumping Stn, Stead St (	ELIN	Leven St 13 LEV 13	2024/07/01	08:15	2024/07/04	09:40	0.75	0.00	3	4405	Unplanned	Other cause	New connection - Relocate RMU & transformer
94805-94805	490/2 Pumping Stn, Stead St (	ELIN	Leven St 13 LEV 13	2024/07/04	07:43	2024/07/04	09:40	0.02	0.00	3	117	Unplanned	Other cause	New connection - Relocate RMU & transformer
94810-94810	266/4 Eye W Of Nith (4)	ELIN	Spey St 9 SPY 9	2024/07/04	09:20	2024/07/04	13:22	0.04	0.00	3	242	Unplanned	Defective equipment	Deterioration - Failed transformer
94810-94810	266/3 Eye W Of Nith (3)	ELIN	Spey St 9 SPY 9	2024/07/04	12:39	2024/07/04	12:48	0.03	0.00	53	9	Unplanned	Defective equipment	Deterioration - Failed transformer
94838-94838	163/3 Ramrig N Of Lewis (3)	ELIN	Spey St 10 SPY 10	2024/07/09	08:12	2024/07/09	11:10	0.50	0.00	50	178	Planned	Planned interruption	Upgrade - RMU maintenance
94843-94843	642/3 Salford S Of Lamond	ELIN	Racecourse Rd 12 RRD 12	2024/07/09	08:22	2024/07/09	14:51	2.41	0.01	110	389	Planned	Planned interruption	Upgrade - RMU maintenance
94838-94838	163/4 Ramrig N Of Lewis (4)	ELIN	Spey St 10 SPY 10	2024/07/09	08:28	2024/07/09	11:15	0.01	0.00	1	167	Planned	Planned interruption	Upgrade - RMU maintenance
95197-95197	Leven St 13	ELIN	Leven St 13 LEV 13	2024/08/20	10:27	2024/08/20	11:02	0.39	0.01	195	35	Unplanned	Third party interference	Third party vehicle - Broken pole
95197-95197	405 Mersey N. Of Bond Pl.	ELIN	Leven St 13 LEV 13	2024/08/20	10:27	2024/08/20	15:18	0.21	0.00	13	292	Unplanned	Third party interference	Third party vehicle - Broken pole
95248-95248	Do 16025	ELIN	Ocean Beach BFE 2	2024/08/26	20:34	2024/08/27	05:05	0.09	0.00	3	511	Planned	Planned interruption	Upgrade - Install earthing points
95248-95248	973 Foreshore Rd	ELIN	Ocean Beach BFE 2	2024/08/26	20:34	2024/08/26	22:34	0.27	0.00	40	120	Planned	Planned interruption	Upgrade - Install earthing points
95292-95292	404 Bond Pl. W. Of Mersey (4	ELIN	Leven St 13 LEV 13	2024/09/01	08:31	2024/09/01	10:09	0.09	0.00	27	98	Planned	Planned interruption	Upgrade - Repair switch
95292-95292	436 Mersey At Spey	ELIN	Leven St 13 LEV 13	2024/09/01	08:31	2024/09/01	10:14	0.06	0.00	33	99	Planned	Planned interruption	Upgrade - Repair switch
95344-95344	Leven St 9	ELIN	Leven St 9 LEV 9	2024/09/03	15:00	2024/09/03	18:57	0.01	0.00	1	237	Planned	Planned interruption	Fleet plan - Transformer maintenance
95344-95344	431/1 Sth Construction Co Bo	ELIN	Leven St 9 LEV 9	2024/09/03	15:03	2024/09/03	18:57	0.03	0.00	2	234	Planned	Planned interruption	Fleet plan - Transformer maintenance
95409-95409	Do 14529	ELIN	Bluff Borough BFE 1	2024/09/07	11:31	2024/09/07	12:09	0.04	0.00	18	38	Unplanned	Defective equipment	Deterioration - Failed lead
95481-95481	685/1 Bourke E Of Windsor	ELIN	Spey St 11 SPY 11	2024/09/10	22:33	2024/09/11	01:35	0.80	0.00	78	182	Planned	Planned interruption	Fleet plan - RMU 680 maintenance
95496-95496	995 Gore E Of Shannon	ELIN	Ocean Beach BFE 2	2024/09/13	13:36	2024/09/13	13:53	0.13	0.01	110	17	Unplanned	Other cause	Allow high load to pass - High load
95505-95505	Leven St 11	ELIN	Leven St 11 LEV 11	2024/09/14	08:00	2024/09/14	12:44	0.02	0.00	1	284	Unplanned	Other cause	5 Yearly maintenance - Service transformer & testing
95509-95509	Do 15854	ELIN	Leven St 9 LEV 9	2024/09/15	08:14	2024/09/15	12:04	0.10	0.00	8	230	Planned	Planned interruption	Fleet plan - Transformer maintenance
95624-95624	Southern 8	ELIN	Southern 8 SOU 8	2024/09/25	18:00	2024/09/25	19:36	0.03	0.00	5	96	Unplanned	Other cause	Upgrade - To replace LV fuseway
95642-95642	174/2 Liffey S Of Thames(2)	ELIN	Leven St 12 LEV 12	2024/09/29	06:00	2024/09/29	08:28	0.02	0.00	2	148	Planned	Planned interruption	Upgrade - RMU Maintenance
95667-95667	995 Gore E Of Shannon	ELIN	Ocean Beach BFE 2	2024/10/02	09:05	2024/10/02	15:24	2.35	0.01	110	379	Planned	Planned interruption	Upgrade - Replace poles, crossarms & insulators
95715-95715	824/3 Rockdale Rd North Of T	ELIN	Racecourse Rd 6 RRD 6	2024/10/08	08:09	2024/10/08	15:30	0.02	0.00	1	441	Planned	Planned interruption	Upgrade - Transformer maintenance
95718-95718	507/5 Conon S Of Tay	ELIN	Spey St 9 SPY 9	2024/10/08	08:15	2024/10/08	10:43	0.01	0.00	1	148	Planned	Planned interruption	Upgrade - Transformer maintenance
95721-95721	995 Gore E Of Shannon	ELIN	Ocean Beach BFE 2	2024/10/08	19:10	2024/10/08	21:14	0.77	0.01	110	124	Unplanned	Defective equipment	Deterioration - Damaged wires
95746-95746	398/2 Anglem At Museum	ELIN	Southern 8 SOU 8	2024/10/10	17:37	2024/10/10	19:43	0.01	0.00	2	126	Planned	Planned interruption	Upgrade - RMU maintenance
95895-95895	974 Barrow E. Of Palmer (974	ELIN	Ocean Beach BFE 2	2024/10/26	17:46	2024/10/27	03:01	0.78	0.00	25	555	Unplanned	Defective equipment	Deterioration - Broken pole
95895-95895	Gore St Cb	ELIN	Ocean Beach BFE 2	2024/10/26	17:46	2024/10/26	19:08	0.27	0.00	59	82	Unplanned	Defective equipment	Deterioration - Broken pole
96134-96134	Spey St 9	ELIN	Spey St 9 SPY 9	2024/11/21	09:28	2024/11/21	12:20	0.02	0.00	2	172	Unplanned	Unknown	Unknown - Blown fuses
96239-96239	Spey St 9	ELIN	Spey St 9 SPY 9	2024/11/30	06:58	2024/11/30	14:02	0.05	0.00	2	424	Unplanned	Other cause	Upgrade - New RMU
96381-96381	Leven St 13	ELIN	Leven St 13 LEV 13	2024/12/08	07:00	2024/12/08	11:33	0.31	0.00	20	273	Planned	Planned interruption	Upgrade - RMU maintenance
96361-96361	Bluff Borough	ELIN	Bluff Borough BFE 1	2024/12/09	01:05	2024/12/09	01:29	0.00	0.00	3	24	Unplanned	Adverse weather	High winds - Failed lead
96383-96383	Spey St 11	ELIN	Spey St 11 SPY 11	2024/12/09	09:33	2024/12/09	10:08	2.35	0.07	1191	35	Unplanned	Defective equipment	Deteriorration - Failed cable "GV"
96383-96383	685/2 Bourke E Of Windsor	ELIN	Spey St 11 SPY 11	2024/12/09	09:33	2024/12/09	10:18	0.42	0.01	166	45	Unplanned	Defective equipment	Deteriorration - Failed cable "GV"
96606-96606	Shannon St S Of Gore St	ELIN	Bluff Borough BFE 1	2024/12/20	15:56	2024/12/20	18:37	1.81	0.01	199	161	Unplanned	Defective equipment	Deteriorration - Broken wire
96606-96606	961 Bann W Of Liffey	ELIN	Bluff Borough BFE 1	2024/12/20	15:56	2024/12/20	17:08	0.87	0.01	213	72	Unplanned	Defective equipment	Deteriorration - Broken wire
96606-96606	Bluff Borough	ELIN	Bluff Borough BFE 1	2024/12/20	15:56	2024/12/20	17:00	0.28	0.00	77	64	Unplanned	Defective equipment	Deteriorration - Broken wire
96606-96606	Bann St Cb Bann St Cb	ELIN	Bluff Borough BFE 1	2024/12/20	15:56	2024/12/20	16:00	0.08	0.02	366	4	Unplanned	Defective equipment	Deteriorration - Broken wire
96658-96658	397/1 Surry Park (1)	ELIN	Spey St 11 SPY 11	2025/01/12	07:00	2025/01/12	09:51	0.10	0.00	10	171	Planned	Planned interruption	Upgrade - RMU 397 maintenance
96715-96715	Do 37376	ELIN	Leven St 9 LEV 9	2025/01/19	07:00	2025/01/19	10:04	0.01	0.00	1	184	Unplanned	Other cause	Upgrade - Replace transformer
96765-96765	585/2 Deveron N Of Don	ELIN	Spey St 12 SPY 12	2025/01/23	09:50	2025/01/23	10:02	0.05	0.00	75	12	Unplanned	Defective equipment	Deteriorration - Failed Halo RMU
96765-96766	Leven St 6	ELIN	Leven St 6 LEV 6	2025/01/23	09:50	2025/01/23	10:02	0.04	0.00	52	12	Unplanned	Defective equipment	Deteriorration - Failed Halo RMU
96782-96782	Southern 9	ELIN	Southern 9 SOU 9	2025/01/24	17:31	2025/01/24	18:16	1.70	0.04	669	45	Unplanned	Third party interference	Third party vehicle - Broken poles
96782-96782	Southern 9	ELIN	Southern 9 SOU 9	2025/01/24	17:31	2025/01/25	08:34	0.20	0.00	4	903	Unplanned	Third party interference	Third party vehicle - Broken poles
96782-96782	357/4 Otepuni At Lindisfarne	ELIN	Southern 9 SOU 9	2025/01/24	17:31	2025/01/25	02:33	0.49	0.00	16	542	Unplanned	Third party interference	Third party vehicle - Broken poles
96917-96917	Bluff Borough	ELIN	Bluff Borough BFE 1	2025/02/10	16:01	2025/02/10	16:30	0.00	0.00	3	29	Unplanned	Defective equipment	Deteriorration - Failed lead
96945-96945	Bann St Cb Bann St Cb	ELIN	Bluff Borough BFE 1	2025/02/12	17:28	2025/02/12	17:59	0.64	0.02	364	31	Unplanned	Third party interference	Safety isolation - Broken wires (telecom)
96981-96981	712/4 Janet W Of Elles Road	ELIN	Southern 10 SOU 10	2025/02/16	23:00	2025/02/17	02:53	1.06	0.00	81	233	Planned	Planned interruption	Upgrade - RMU & transformer maintenance
96998-96998	995 Gore E Of Shannon	ELIN	Ocean Beach BFE 2	2025/02/18	11:18	2025/02/18	11:34	0.16	0.01	110	16	Unplanned	Other cause	Safety isolation - Allow high load to pass
97138-97138	170/1 Victoria Av Opp Thoma	ELIN	Spey St 6 SPY 6	2025/03/02	07:00	2025/03/02	11:03	1.21	0.00	88	243	Planned	Planned interruption	Upgrade - RMU maintenance
97287-97287	Leven St 11	ELIN	Leven St 11 LEV 11	2025/03/17	21:12	2025/03/17	22:08	1.89	0.03	597	56	Unplanned	Third party interference	Third party vehicle - Car hit RMU/transformer 225
97287-97287	Leven St 11	ELIN	Leven St 11 LEV 11	2025/03/17	21:12	2025/03/18	01:15	1.15	0.00	84	243	Unplanned	Third party interference	Third party vehicle - Car hit RMU/transformer 225

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

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2025

SCHEDULE 11c: REPORT ON CYBERSECURITY EXPENDITURE FORECAST

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

sch ref

11c Expenditure Forecast — $000 (in constant prices)

	Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
Capex Forecast											
Cybersecurity (Commission only)	-	-	-	-	-	-	-	-	-	-	-
Opex Forecast											
Cybersecurity (Commission only)	6	10	10	10	10	10	10	10	10	10	10

SCHEDULE 14 MANDATORY EXPLANATORY NOTES

(Guidance Note: This Microsoft Word version of Schedules 14, 14a and 15 is from the Distribution Information Disclosure Determination 2012 – as amended and consolidated 3 April 2018. Clause references in this template are to that determination).

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

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

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

Return on Investment (Schedule 2)

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

Box 1: Explanatory comment on return on investment

Electricity Invercargill Limited (EIL) achieved a post-tax ROI of 4.85% which is below the 75th percentile estimate of post-tax WACC of 6.86%. EIL also achieved a 5.57% vanilla ROI which is below the 75th percentile estimate of vanilla WACC of 7.58%.

No items were reclassified.

Regulatory Profit (Schedule 3)

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

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

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

Box 2: Explanatory comment on regulatory profit

Other regulated income of $73k is for line charges to another lines company for the use of a circuit breaker ad feeder.to supply some customers from an EIL substation.

No items were reclassified in the disclosure year.

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

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

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

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

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

Value of the Regulatory Asset Base (Schedule 4)

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

Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)
The calculation of the Regulatory Asset Base (RAB) was stated using the 31 March 2024 closing figure of $113,034k as a starting point with inflationary indexing over the year to 31 March 2025, plus additions less disposals. This resulted in a closing RAB balance of $119,114k.

Additions during the year amounted to $7,667k, of which approximately 60% or $4,600 has been attributed to related party transactions. This allocation has been estimated due to the change of ownership during the year. The allocation was determined based on the proportion of capital expenditure incurred with the related party prior to the change of ownership.

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 $7k 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:	$	318
	$	318
Tax Rate:		28%
Temporary Differences	$	89

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 and disclosed in Schedule 6b.

Variance between forecast and actual expenditure (Schedule 7)

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

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

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

Capital Expenditure:

The actual expenditure on network assets was 4% above budget.

Consumer connection:

- 41% underspend was primarily due to lower than forecast development activity in new subdivisions, and the deferral of a reconductoring project which is currently being re-evaluated to identify a more cost effective delivery option.

Asset replacement and renewal:

- No material variance with actual expenditure broadly in line with the forecast.

Asset Relocations:

- The overspend was driven by hotel development activity that required the relocation of a link box.

Quality of Supply:

- 62% above target primarily due to the completion of the RMU automation project, which has been deferred from previous year because of supply constraints. In addition the completion of the fault indicator project, which was undertaken by external specialist contractors resulted in a higher than budgeted expenditure.

Reliability, Safety and Environment:

- 47% overspend due to higher than anticipated traffic management costs and increased spending on earth upgrades due to scope change, required as a result of an increase in CBD network earthing works over the past two years.

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

Operational Expenditure:

The actual operational expenditure was 6% below budget.

Service interruptions and emergencies:

- 8% underspend due to lower faults than anticipated.

Vegetation management:

- 16% underspend on a $2k budget because of fewer vegetation clearance work identified during the year than anticipated.

Routine and corrective maintenance and inspection:

- 30% underspend due to limited work identified from the inspection programme.

Asset replacement and renewal:

- 37% underspend due to fewer assets requiring renewal than initially forecast, following condition assessments undertaken during field inspections.

Non-network opex:

System operations and network support

- 4% underspent primarily due to the planned captive insurance timing.

Business support

- 14% overspent due to higher administration costs, including consultancy and legal fees. These reflect engagement with external specialist to support strategic projects, compliance initiatives and regulatory matters.

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 $19,658k. The total billed revenue for the year was $19,947k, which is $289k above.

The favourable variance is a combination of additional volume due to colder weather and new industrial connections. This increased the underlying line charge revenue, making it slightly higher (1% variation) than the targeted result

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 13: Commentary on network reliability for the disclosure year

Electricity Invercargill Limited (EIL) has calculated and disclosed SAIDI and SAIFI metrics consistent with the 2012 Electricity Distribution Business (EDB) ID Determination, incorporating all amendments up to and including 27 November 2024.

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

Prior to the 2023/2024 disclosure year, EIL did not include successive interruptions to the same ICP after the initial interruption when calculating SAIFI. For continuity, this calculation method is recorded in Schedule 10, reference rows 37-38 (Transitional SAIFI and SAIDI – previous method). Transitional SAIFI figures can be compared to reference rows 26-27 of disclosures prior to the 2024 disclosure year.

Class C (unplanned) interruption SAIDI increased by 21%, from 17.07 to 21.00 minutes, while Class B (planned) SAIDI increased by 7.4% from 23.97 to 25.75. The total number of Class C interruptions decreased slightly from 26 to 25, and Class B interruptions decreased from 32 to 30. The number of interruptions exceeding 3 hours duration increased by two.

Class C SAIFI, at 0.3472, was the major contributor (53%) to the total SAIFI figure. The most significant cause of Class C interruptions was defective equipment, making up over 50% of both unplanned SAIDI and SAIFI totals.

Only 10% of EIL's network consists of overhead distribution lines, yet 67% of unplanned interruptions, based on SAIDI, occurred on these lines. The fault rate for distribution lines per 100 km increased by 50% to 61.8, with the distribution cable fault rate increasing by 25% to 3.13. No faults occurred on the subtransmission lines or cables.

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

This is the first year of disclosing the worst performing feeder rankings in terms of SAIDI, SAIFI and customer impact.

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 $39.5 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 2023:

	2025	2026	2027	2028	2029
Inflator (CAPEX & OPEX)	4.1%	2.5%	2.2%	2.0%	2.0%

In addition to the general inflation, material costs have increased by a weighted average of 9.0% in 2023 and labour and external services costs have increased by 4.35%. These increases are included in the CAPEX forecasts for 2024 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 5b

Electricity Invercargill Limited disposed of its entire shareholding in subsidiary, Pylon Limited effective 1 December 2024. As part of this transaction, Electricity Invercargill Limited sold its interest in the joint ventures OtagoNet Joint Venture and PowerNet Limited and associate Lakeland Network Limited. As a result, all the disclosed related party transactions with PowerNet Limited relate to the period prior to acquisition, covering first eight months of the year.

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).

This year the accuracy of reported outage data has been improved by comparing it to available smart meter power-down event data. These variations have been used to find and correct discrepancies.

Also, an action time field has been added to recorded operating sequences, so that recorded outage time better represents the action as opposed to the communication of the completion of the action.

Several actions and initiatives are being taken to overcome these limitations, including improved visibility and analysis of smart meter data, strengthening of processes relating to the recording of outages from the outage system, and retention of documentation.

Schedule 11c

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

4. APPENDIX - Related Party Transactions:

Additional Information Disclosure

4.1 INTRODUCTION

For the purpose of meeting the 2025 Related Party Transaction reporting requirements, in accordance with section 2.3.6 of the Electricity Distribution Information Disclosure (Targeted Review 2024) Amendment Determination 2024 [2024] NZCC 2. Due to the sale of EIL's investments as at 29 November 2024 the information reported in this appendix relates to the 8 months prior to sale being April 24 to November 24. After the sale EIL had no related party transactions that were required to be disclosed.

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

- **Electricity Invercargill Limited's 2025 Information Disclosure**, for the year ended 31 March 2025 - 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 ended 31 March 2025.

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) had 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. In June 2024 Pylon sold the Southern Generation Limited Partnership interest and in November 2024 the interests in PowerNet Limited, the OtagoNet Joint Venture and Lakeland Network Limited were also sold.

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

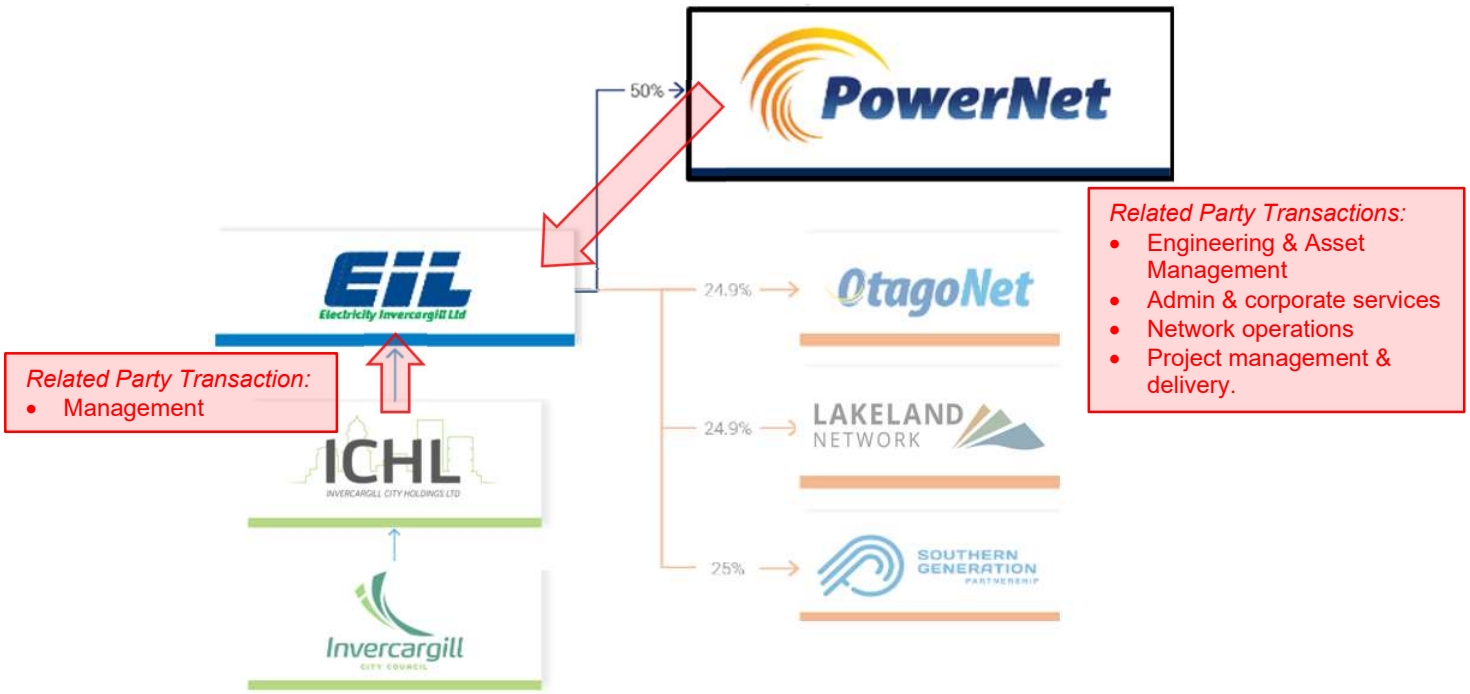
- Goods and services provided by – PowerNet Limited; Invercargill City Holdings Limited and Invercargill City Council.

The transactions between EIL and PowerNet are subject to Related Party Transaction reporting until 29 November 2024.

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 until 29 November 2024, and the nature of related party transaction work undertaken.

Diagram below reflects related party interest up to 29 November 2024



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 8 month period ended November 2024 is categorised as follows:

		($'000)
Operating Expenditure:		
i.	Service interruptions and emergencies	434
ii.	Routine and corrective maintenance and inspection	862
iii.	Asset replacement and renewal (opex)	93
iv.	Business support	1,176
v.	System operations and network support	494
vi.	Vegetation Management	2
Capital Expenditure		
i.	Consumer Connection	506
ii.	Asset replacement and renewal (capex)	2,267
iii.	Asset relocations	27
iv.	Quality of supply	219
v.	Other reliability, safety and environment	1,406
Total Related Party expenditure from PowerNet		**7,486**

In the period ended 30 November 2024, PowerNet provided 100% of the EIL Lines Business Capital Expenditure, and 91% 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, cybersecurity and human resources
- Corporate, finance and commercial services

b. Invercargill City Holdings Limited

EIL is wholly-owned by the Invercargill City Council (ICC) through its subsidiary company, 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 2025 is categorised as follows:

		($'000)
Operating Expenditure:		
i.	Business support	155
ii.	Other related party transaction	198
Total Related Party expenditure from ICHLand ICC		**353**

For the 12 months to 31 March 2025, ICC and ICHL transactions represented 5% of all Operating Expenditure, relating to management fees and rates.

c. Directors Fees

In the year to 31 March 2025 directors fees were $149k. EIL Directors Fees represented 2% of all Operating Expenditure for the year ended 31 March 2025.

	($'000)
Operating Expenditure:	
Directors Fees	149
Total Related Party expenditure to Directors by EIL	**149**

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 2025 AS REQUIRED BY THE ELECTRICITY DISTRIBUTION INFORMATION DISCLOSURE (AMENDMENTS RELATED TO IM REVIEW 2023) AMENDMENT DETERMINATION 2024 [2024] NZCC 31

The Electricity Invercargill Limited (the company) is required to disclose certain information under the Electricity Distribution Information Disclosure (Amendments related to IM Review 2023) Amendment Determination 2024 [2024] NZCC 31 (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 2025 (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 (excluding 3a),[1] 5a to 5h, 6a and 6b, 7, 10 and 10a (limited to the SAIDI and SAIFI information) and 14 (limited to the explanatory notes in boxes 1 to 11) of the Determination.
- Clause 2.3.6 of the Determination and clauses 2.2.11(1)(g), 2.2.11(5) and 2.2.11(6) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 23 April 2024) (the IM Determination), in respect of the basis for valuation of related party transactions (the Related Party Transaction Information).

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.

[1] Schedule 3a requirement applies from 1 April 2025, which is the beginning of disclosure year 2026. As such, the first disclosures will be due in 2026.

Basis for Qualified Opinion
As described in box 1 of Schedule 15, there are inherent limitations in the ability of the Company to collect and record the network reliability information specifically the interconnection points ('ICP's') affected by an interruption and the duration of the interruption used in calculating the amounts required to be disclosed in the Schedules 10(i) to 10(vi) and 10a. Consequently, there is no independent evidence available to support the completeness and accuracy of recorded faults, and control over the completeness and accuracy of interconnection point ('ICP') data included in the SAIDI and SAIFI calculations was limited throughout the year.

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

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

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

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

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

Key Assurance Matter	How our procedures addressed the key assurance matter
Regulatory asset base The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of 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	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination. Our procedures over the regulatory asset base included the following: **Assets commissioned** • We considered the nature of the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB; • We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions

Key Assurance Matter	How our procedures addressed the key assurance matter
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.	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 • 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 considered the nature of the asset disposals within the accounting fixed asset register and tested a sample of RAB disposals to ensure disposals in the RAB meet the definition of a disposal per the IM Determination.
Cost and Asset Allocation The Determination relates to information concerning the supply of electricity distribution services. In addition to the regulated supply of electricity, Electricity Invercargill Limited also supplies customers with other unregulated services such as metering services. As set out in schedules 5d, 5e, 5f and 5g, costs and asset values that relate to electricity distribution services regulated under the Determination should comprise: • All of the costs directly attributable to the regulated goods or services; and • An allocated portion of the costs that are not directly attributable.	We obtained an understanding of Electricity Invercargill Limited's cost and asset allocation processes and the methodologies applied. Our procedures over cost and asset allocation included: • Reconciling the regulated and unregulated financial information to the audited financial statements. **Classification as directly/not directly attributable** • Considering the appropriateness of the costs allocated as directly attributable, based on the nature and our understanding of the business to determine the reasonableness of the directly attributable classification; • Testing a sample of transactions to ensure their classification as either directly attributable or not directly attributable costs are appropriate and in line with the Determination, as amended; • Inspecting the fixed asset register to identify any asset classes which based on their nature and our

Key Assurance Matter	How our procedures addressed the key assurance matter
The IM Determination set out rules and processes for allocating costs and assets which are not directly attributable to either regulated or unregulated services. A number of screening tests apply which must be considered when deciding on the appropriate allocation method. Electricity Invercargill Limited has applied the Accounting-Based Allocation Approach Methodology (ABAA) utilising proxy cost and asset allocators to allocate the asset values and operating costs that are not directly attributable where causal relationships could not be identified. Given the judgement involved in the application of the cost and asset allocation methodologies we consider it a key assurance matter.	understanding of the business could be considered assets directly attributable to a specific business unit; and • Testing a sample of assets commissioned to ensure their classification as either directly attributable or not directly attributable are appropriate and in line with the Determination, as amended, by inspecting the related invoice. **Appropriateness of the allocators used for not directly attributable costs and assets** • Considering the appropriateness of the cost and asset causal and proxy allocators used in applying the ABAA to not directly attributable costs including inspecting supporting documentation and recalculating proxy allocators; • Understanding why causal relationships could not be identified in allocating some costs or assets and ensuring appropriate disclosure has been included outlining these in Schedule 14; and • Recalculating the split between not directly attributable costs and asset values allocated to electricity distribution services and non-electricity distribution services.
Related party transactions Disclosures over related party transactions including related party relationships, procurement policies/processes, application of these policies/processes and examples of market testing of transaction terms as required under the Determination and the IM Determination are set out in the Appendix A. 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	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 A includes all required disclosures including current procurement policies, descriptions of how they are applied in practice, representative example transactions and when and how market testing was last performed. Our procedures over the related party transactions included the following: **Completeness and accuracy of related party relationships and transactions** We have tested the completeness and accuracy of the related party relationships and transactions by: • Agreeing the disclosures within Schedule 5(b) to the audited financial statements for the year ended 31 March 2025 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

Key Assurance Matter	How our procedures addressed the key assurance matter
or supply to a related party cannot be valued at an amount less than if it had been sold or supplied under the terms of an arm's-length transaction with an unrelated party. Arm's-length valuation, as defined in the IM Determination, is the value at which a transaction, with the same terms and 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.	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 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), 2.2.11(5) and 2.2.11(6) of the IM Determination.

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

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

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

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

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

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

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

The Auditor-General, and his employees, PricewaterhouseCoopers and its partners and employees may deal with the company on normal terms within the ordinary course of trading activities of the company. Other than any dealings on normal terms within the ordinary course of trading activities of the company, this engagement, the assurance engagement on the Default Price-Quality Path, assurance engagements on regulatory compliance with the Commerce Act 1986 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
29 August 2025

6. DIRECTORS' CERTIFICATE

Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

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

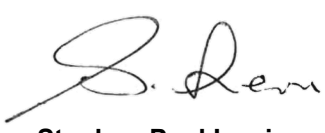
a) the information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.3.8 – 2.3.12, 2.4.21, 2.4.22, 2.5.1(1)(a)-(f), 2.5.2, 2.5.2A and 2.7.1 of the Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 in all material respects complies with that determination; and

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

c) In respect of information concerning assets, costs and revenues valued or disclosed in accordance with clause 2.3.6 of the Electricity Distribution Information Disclosure (amendments related to IM Review 2023) Amendment Determination 2024 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 (amendments related to IM Review 2023) Amendment Determination 2024 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 (amendments related to IM Review 2023) Amendment Determination 2024.



Stephen Paul Lewis



Peter James Heenan

29 August 2025

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