Information Disclosure prepared in accordance with Electricity Information Disclosure Determination under Part 4 of the Commerce Act 1986

For the Year Ended 31 March 2020

CONTENTS

1. INTRODUCTION

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

- The Electricity Information Disclosure Determination 2012 (consolidated in 2018), issued 3 April 2018,
- The Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 2014), issued 30 March 2015,

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 2020**

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 the ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of the determination.

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

sch ref

7 **1(i): Expenditure metrics**

sch ref		Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
8						
9	**Operational expenditure**	20,432	296	81,573	7,815	34,260
10	Network	8,221	119	32,822	3,145	13,785
11	Non-network	12,211	177	48,751	4,671	20,475
12						
13	**Expenditure on assets**	18,782	272	74,987	7,184	31,493
14	Network	18,782	272	74,987	7,184	31,493
15	Non-network	–	–	–	–	–
16						

17 **1(ii): Revenue metrics**

sch ref		Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
18			
19	**Total consumer line charge revenue**	82,405	1,192
20	Standard consumer line charge revenue	82,405	1,192
21	Non-standard consumer line charge revenue	–	–
22			

23 **1(iii): Service intensity measures**

sch ref			
24			
25	Demand density	94	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	382	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	26	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	14,464	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*
29			

30 **1(iv): Composition of regulatory income**

sch ref		($000)	% of revenue
31			
32	Operational expenditure	5,146	24.87%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	6,829	33.01%
34	Total depreciation	3,225	15.59%
35	Total revaluations	2,191	10.59%
36	Regulatory tax allowance	1,594	7.70%
37	Regulatory profit/(loss) including financial incentives and wash-ups	6,088	29.42%
38	**Total regulatory income**	20,689	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	7.90	*Interruptions per 100 circuit km*

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2020

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 the 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 the 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
	31 Mar 18	31 Mar 19	31 Mar 20
ROI – comparable to a post tax WACC	%	%	%
Reflecting all revenue earned	5.78%	6.29%	6.94%
Excluding revenue earned from financial incentives	5.81%	6.15%	6.93%
Excluding revenue earned from financial incentives and wash-ups	5.73%	6.08%	6.85%
Mid-point estimate of post tax WACC	5.04%	4.75%	4.27%
25th percentile estimate	4.36%	4.07%	3.59%
75th percentile estimate	5.72%	5.43%	4.95%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	6.37%	6.80%	7.37%
Excluding revenue earned from financial incentives	6.40%	6.66%	7.35%
Excluding revenue earned from financial incentives and wash-ups	6.32%	6.58%	7.27%
WACC rate used to set regulatory price path	7.19%	7.19%	7.19%
Mid-point estimate of vanilla WACC	5.60%	5.26%	4.69%
25th percentile estimate	4.92%	4.58%	4.01%
75th percentile estimate	6.29%	5.94%	5.37%

2(ii): Information Supporting the ROI

			($000)	
	Total opening RAB value	86,605		
plus	Opening deferred tax	(3,889)		
Opening RIV			82,716	
Line charge revenue			20,753	
	Expenses cash outflow	11,974		
add	Assets commissioned	3,587		
less	Asset disposals	125		
add	Tax payments	1,172		
less	Other regulated income	(64)		
Mid-year net cash outflows			16,672	
Term credit spread differential allowance			–	
	Total closing RAB value	89,033		
less	Adjustment resulting from asset allocation	0		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(4,311)		
Closing RIV			84,722	
ROI – comparable to a vanilla WACC				7.37%
	Leverage (%)			42%
	Cost of debt assumption (%)			3.61%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				6.94%

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	7.08%
Year-end ROI – comparable to a post tax WACC	6.65%

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

2(v): Financial Incentives and Wash-Ups

Net recoverable costs allowed under incremental rolling incentive scheme	–	
Purchased assets – avoided transmission charge		
Energy efficiency and demand incentive allowance		
Quality incentive adjustment	15	
Other financial incentives		
Financial incentives		15
Impact of financial incentives on ROI		0.01%
Input methodology claw-back		
CPP application recoverable costs		
Catastrophic event allowance		
Capex wash-up adjustment	92	
Transmission asset wash-up adjustment		
2013–15 NPV wash-up allowance		
Reconsideration event allowance		
Other wash-ups		
Wash-up costs		92
Impact of wash-up costs on ROI		0.08%

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2020**

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 the 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	20,753
10	*plus*	Gains / (losses) on asset disposals	(123)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	59
12			
13		**Total regulatory income**	20,689
14		**Expenses**	
15	*less*	Operational expenditure	5,146
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	6,829
18			
19		**Operating surplus / (deficit)**	8,715
20			
21	*less*	Total depreciation	3,225
22			
23	*plus*	Total revaluations	2,191
24			
25		**Regulatory profit / (loss) before tax**	7,681
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	1,594
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	6,088
32			

		($000)	
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**		
34	**Pass through costs**		
35	Rates	127	
36	Commerce Act levies	41	
37	Industry levies	56	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	6,221	
41	Transpower new investment contract charges	383	
42	System operator services		
43	Distributed generation allowance		
44	Extended reserves allowance		
45	Other recoverable costs excluding financial incentives and wash-ups		
46	**Pass-through and recoverable costs excluding financial incentives and wash-ups**		6,829
47			

			($000)	
48	**3(iii): Incremental Rolling Incentive Scheme**			
49			**CY-1**	**CY**
50			**31 Mar 19**	**31 Mar 20**
51	Allowed controllable opex		–	
52	Actual controllable opex		–	
53				
54	Incremental change in year			
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57	CY-5	31 Mar 15	–	
58	CY-4	31 Mar 16	–	
59	CY-3	31 Mar 17	–	
60	CY-2	31 Mar 18	–	
61	CY-1	31 Mar 19	–	
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–

65	**3(iv): Merger and Acquisition Expenditure**	
70		($000)
66	Merger and acquisition expenditure	
67		
68	*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*	
69	**3(v): Other Disclosures**	
70		($000)
71	Self-insurance allowance	

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2020

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 the 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	RAB	RAB	RAB	RAB
for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
	($000)	($000)	($000)	($000)	($000)
Total opening RAB value	74,188	77,667	80,292	84,072	86,605
less **Total depreciation**	2,789	2,885	2,925	3,120	3,225
plus **Total revaluations**	435	1,676	882	1,245	2,191
plus **Assets commissioned**	5,869	4,103	5,907	4,533	3,587
less **Asset disposals**	36	269	85	126	125
plus **Lost and found assets adjustment**					–
plus **Adjustment resulting from asset allocation**					0
Total closing RAB value	77,667	80,292	84,072	86,605	89,033

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Total opening RAB value		86,605		86,605
less				
Total depreciation		3,225		3,225
plus				
Total revaluations		2,191		2,191
plus				
Assets commissioned (other than below)				
Assets acquired from a regulated supplier				
Assets acquired from a related party	3,587		3,587	
Assets commissioned		3,587		3,587
less				
Asset disposals (other than below)	102		102	
Asset disposals to a regulated supplier				
Asset disposals to a related party	23		23	
Asset disposals		125		125
plus **Lost and found assets adjustment**				
plus **Adjustment resulting from asset allocation**				0
Total closing RAB value		89,033		89,033

** 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	1,052
CPI_4^{-4}	1,026
Revaluation rate (%)	2.53%

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Total opening RAB value	86,605		86,605	
less Opening value of fully depreciated, disposed and lost assets	142		142	
Total opening RAB value subject to revaluation	86,463		86,463	
Total revaluations		2,191		2,191

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		1,003		1,003
plus Capital expenditure	4,689		4,689	
less Assets commissioned	3,587		3,587	
plus Adjustment resulting from asset allocation				
Works under construction - current disclosure year		2,105		2,105
Highest rate of capitalised finance applied				

4(v): Regulatory Depreciation

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Depreciation - standard	3,225		3,225	
Depreciation - no standard life assets				
Depreciation - modified life assets				
Depreciation - alternative depreciation in accordance with CPP				
Total depreciation		3,225		3,225

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	54	6,921	16,615	2,081	42,473	9,986	5,205	3,269		86,605
less	Total depreciation	2	206	561	96	1,489	422	265	184		3,225
plus	Total revaluations	1	176	421	52	1,075	252	130	83		2,191
plus	Assets commissioned	–	–	1,156	79	1,274	646	297	136		3,587
less	Asset disposals	–	–	12	18	–	49	46	–		125
plus	Lost and found assets adjustment										–
plus	Adjustment resulting from asset allocation										–
plus	Asset category transfers										–
	Total closing RAB value	54	6,891	17,619	2,098	43,333	10,413	5,321	3,303	–	89,033
	Asset Life										
	Weighted average remaining asset life	26	39	34	30	35	26	23	19		(years)
	Weighted average expected total asset life	47	57	53	59	58	45	39	38		(years)

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2020**

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 the 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**			7,681
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	1,264		
13		Amortisation of revaluations	315		
14					1,578
15					
16	*less*	Total revaluations	2,191		
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	144	*	
20		Notional deductible interest	1,232		
21					3,568
22					
23		**Regulatory taxable income**			5,692
24					
25	*less*	Utilised tax losses			
26		Regulatory net taxable income			5,692
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			1,594
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	22,743		
37	*less*	Amortisation of initial differences in asset values	1,264		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	95		
40		Closing unamortised initial differences in asset values			21,384
41					
42		Opening weighted average remaining useful life of relevant assets (years)			18
43					

5a(iv): Amortisation of Revaluations

				($000)
44				
46		Opening sum of RAB values without revaluations	78,828	
48		Adjusted depreciation	2,910	
49		Total depreciation	3,225	
50		Amortisation of revaluations		315

5a(v): Reconciliation of Tax Losses

				($000)
54		**Opening tax losses**	–	
55	*plus*	Current period tax losses	–	
56	*less*	Utilised tax losses	–	
57		**Closing tax losses**		–

5a(vi): Calculation of Deferred Tax Balance

				($000)
60		**Opening deferred tax**	(3,889)	
62	*plus*	Tax effect of adjusted depreciation	815	
64	*less*	Tax effect of tax depreciation	923	
66	*plus*	Tax effect of other temporary differences*	22	
68	*less*	Tax effect of amortisation of initial differences in asset values	354	
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year	–	
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	(18)	
74	*plus*	Deferred tax cost allocation adjustment	(0)	
76		**Closing deferred tax**		(4,311)

5a(vii): Disclosure of Temporary Differences

79 *In Schedule 14, Box 6, provide descriptions and workings of items recorded in the asterisked category in Schedule 5a(vi) (Tax effect of other temporary differences).*

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

				($000)
83		**Opening sum of regulatory tax asset values**	42,645	
84	*less*	Tax depreciation	3,297	
85	*plus*	Regulatory tax asset value of assets commissioned	3,657	
86	*less*	Regulatory tax asset value of asset disposals	29	
87	*plus*	Lost and found assets adjustment	–	
88	*plus*	Adjustment resulting from asset allocation	–	
89	*plus*	Other adjustments to the RAB tax value	–	
90		**Closing sum of regulatory tax asset values**		42,976

Company Name	Electricity Invercargill Limited
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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 the ID determination.
This information is part of audited disclosure information (as defined in clause 1.4 of the ID determination), and so is subject to the assurance report required by clause 2.8.

sch ref			
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		–
9			
10	**Market value of asset disposals**		23
11			
12	Service interruptions and emergencies	597	
13	Vegetation management	10	
14	Routine and corrective maintenance and inspection	1,358	
15	Asset replacement and renewal (opex)	106	
16	**Network opex**		2,070
17	Business support	1,544	
18	System operations and network support	299	
19	**Operational expenditure**		3,914
20	Consumer connection	519	
21	System growth	–	
22	Asset replacement and renewal (capex)	3,955	
23	Asset relocations	–	
24	Quality of supply	71	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	186	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		4,730
29	Cost of financing		
30	Value of capital contributions		
31	Value of vested assets		
32	**Capital Expenditure**		4,730
33	**Total expenditure**		8,644
34			
35	**Other related party transactions**		

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

36			
37	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
38	PowerNet Limited	Routine and corrective maintenance and inspection	1,358
39	PowerNet Limited	Asset replacement and renewal (opex)	106
40	PowerNet Limited	Service interruptions and emergencies	597
41	PowerNet Limited	Vegetation management	10
42	PowerNet Limited	Business Support	1,389
43	Invercargill City Holdings	Business Support	155
44	PowerNet Limited	Consumer connection	519
45	PowerNet Limited	Asset replacement and renewal (capex)	3,955
47	PowerNet Limited	Other reliability, safety and environment	186
48	PowerNet Limited	Quality of supply	71
49	PowerNet Limited	System operations and network support	299
50			
51			
52			
53	**Total value of related party transactions**		8,644
54	** include additional rows if needed*		
55			

Company Name	Electricity Invercargill Limited
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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 the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7

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

9

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

17

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

19

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

Company Name	Electricity Invercargill Limited
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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 the 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		597			
Not directly attributable				–	
Total attributable to regulated service		597			
Vegetation management					
Directly attributable		10			
Not directly attributable				–	
Total attributable to regulated service		10			
Routine and corrective maintenance and inspection					
Directly attributable		1,358			
Not directly attributable				–	
Total attributable to regulated service		1,358			
Asset replacement and renewal					
Directly attributable		106			
Not directly attributable				–	
Total attributable to regulated service		106			
System operations and network support					
Directly attributable		1,029			
Not directly attributable				–	
Total attributable to regulated service		1,029			
Business support					
Directly attributable		1,756			
Not directly attributable		290	19	309	
Total attributable to regulated service		2,046			
Operating costs directly attributable		4,855			
Operating costs not directly attributable	–	290	19	309	–
Operational expenditure		5,146			

5d(ii): Other Cost Allocations

	($000)
Pass through and recoverable costs	
Pass through costs	
Directly attributable	224
Not directly attributable	–
Total attributable to regulated service	224
Recoverable costs	
Directly attributable	6,604
Not directly attributable	–
Total attributable to regulated service	6,604

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

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

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

			($000) CY-1	($000) Current Year (CY)
Change in cost allocation 3				
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

pwc

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2020**

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 the 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	54
Not directly attributable	
Total attributable to regulated service	54
Subtransmission cables	
Directly attributable	6,891
Not directly attributable	
Total attributable to regulated service	6,891
Zone substations	
Directly attributable	17,619
Not directly attributable	
Total attributable to regulated service	17,619
Distribution and LV lines	
Directly attributable	2,098
Not directly attributable	
Total attributable to regulated service	2,098
Distribution and LV cables	
Directly attributable	43,333
Not directly attributable	
Total attributable to regulated service	43,333
Distribution substations and transformers	
Directly attributable	10,413
Not directly attributable	
Total attributable to regulated service	10,413
Distribution switchgear	
Directly attributable	5,321
Not directly attributable	
Total attributable to regulated service	5,321
Other network assets	
Directly attributable	3,303
Not directly attributable	
Total attributable to regulated service	3,303
Non-network assets	
Directly attributable	
Not directly attributable	
Total attributable to regulated service	–
Regulated service asset value directly attributable	89,033
Regulated service asset value not directly attributable	–
Total closing RAB value	89,033

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

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

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

			($000) CY-1	Current Year (CY)
Change in asset value allocation 3				
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 2020**

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

sch ref	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%) Electricity distribution services	Allocator Metric (%) Non-electricity distribution services	Value allocated ($000) Arm's length deduction	Value allocated ($000) Electricity distribution services	Value allocated ($000) Non-electricity distribution services	Value allocated ($000) Total	OVABAA allocation increase ($000)
7											
8											
11	**Service interruptions and emergencies**										
12										-	
13										-	
14										-	
15										-	
16	**Not directly attributable**						-	-	-	-	-
17	**Vegetation management**										
18										-	
19										-	
20										-	
21										-	
22	**Not directly attributable**						-	-	-	-	-
23	**Routine and corrective maintenance and inspection**										
24										-	
25										-	
26										-	
27										-	
28	**Not directly attributable**						-	-	-	-	-
29	**Asset replacement and renewal**										
30										-	
31										-	
32										-	
33										-	
34	**Not directly attributable**						-	-	-	-	-
35											
36	**System operations and network support**										
37										-	
38										-	
39										-	
40										-	
41	**Not directly attributable**						-	-	-	-	-
42	**Business support**										
43	Administration Expenses	ABAA	Revenue	Proxy	93.83%	6.17%		290	19	309	
44										-	
45										-	
46										-	
47	**Not directly attributable**						-	290	19	309	-
48											
49	**Operating costs not directly attributable**						-	290	19	309	-
50											
51	**Pass through and recoverable costs**										
52	**Pass through costs**										
53										-	
54										-	
55										-	
56										-	
57	**Not directly attributable**						-	-	-	-	-
58	**Recoverable costs**										
59										-	
60										-	
61										-	
62										-	
63	**Not directly attributable**						-	-	-	-	-
64	** include additional rows if needed*										

Company Name **Electricity Invercargill Limited**
For Year Ended **31 March 2020**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

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

sch ref											
7											
8											
9					Allocator Metric (%)		Value allocated ($000)				
10	Line Item*	Allocation methodology type	Allocator	Allocator type	Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000)
11	**Subtransmission lines**										
12										-	
13										-	
14										-	
15										-	
16	Not directly attributable						-	-	-	-	-
17	**Subtransmission cables**										
18										-	
19										-	
20										-	
21										-	
22	Not directly attributable						-	-	-	-	-
23	**Zone substations**										
24										-	
25										-	
26										-	
27										-	
28	Not directly attributable						-	-	-	-	-
29	**Distribution and LV lines**										
30										-	
31										-	
32										-	
33										-	
34	Not directly attributable						-	-	-	-	-
35	**Distribution and LV cables**										
36										-	
37										-	
38										-	
39										-	
40	Not directly attributable						-	-	-	-	-
41											
42	**Distribution substations and transformers**										
43										-	
44										-	
45										-	
46										-	
47	Not directly attributable						-	-	-	-	-
48											
49	**Distribution switchgear**										
50										-	
51										-	
52										-	
53										-	
54	Not directly attributable						-	-	-	-	-
55	**Other network assets**										
56										-	
57										-	
58										-	
59										-	
60	Not directly attributable						-	-	-	-	-
61	**Non-network assets**										
62										-	
63										-	
64										-	
65										-	
66	Not directly attributable						-	-	-	-	-
67											
68	Regulated service asset value not directly attributable						-	-	-	-	-
69	** include additional rows if needed*										

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2020**

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

sch ref				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		519
9		System growth		–
10		Asset replacement and renewal		3,955
11		Asset relocations		–
12		Reliability, safety and environment:		
13		Quality of supply	71	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	186	
16		**Total reliability, safety and environment**		257
17		**Expenditure on network assets**		4,730
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		4,730
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		41
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		4,689
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		–
28		Overhead to underground conversion		–
29		Research and development		–
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Customer Connections < 20 kVA	83	
33		Customer Connections 21 - 99 kVA	37	
34		Customer Connections > 100 kVA	393	
		New Subdivisions	6	
35				
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		519
39				
40	*less*	Capital contributions funding consumer connection expenditure	41	
41		**Consumer connection less capital contributions**		478

42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement**
43			**System Growth**	**and Renewal**
44			**($000)**	**($000)**
45		Subtransmission	–	–
46		Zone substations	–	2,307
47		Distribution and LV lines	–	35
48		Distribution and LV cables	–	248
49		Distribution substations and transformers	–	1,095
50		Distribution switchgear	–	–
51		Other network assets	–	269
52		**System growth and asset replacement and renewal expenditure**	–	3,955
53	*less*	Capital contributions funding system growth and asset replacement and renewal		–
54		**System growth and asset replacement and renewal less capital contributions**	–	3,955
55				

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

68				
69	**6a(vi): Quality of Supply**			
70		*Project or programme**	($000)	($000)
71		20350 - Network Automation Projects	71	
72			–	
73			–	
74			–	
75			–	
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	–	
78		**Quality of supply expenditure**		71
79	*less*	Capital contributions funding quality of supply	–	
80		**Quality of supply less capital contributions**		71
81	**6a(vii): Legislative and Regulatory**			
82		*Project or programme**	($000)	($000)
83			–	
84			–	
85			–	
86			–	
87			–	
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory	–	
90		**Legislative and regulatory expenditure**		–
91	*less*	Capital contributions funding legislative and regulatory	–	
92		**Legislative and regulatory less capital contributions**		–
93	**6a(viii): Other Reliability, Safety and Environment**			
94		*Project or programme**	($000)	($000)
95		20450 - Earth Upgrades - City	2	
96		20458 - Pillar Box Lid Upgrade	184	
97			–	
98			–	
99			–	
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	–	
102		**Other reliability, safety and environment expenditure**		186
103	*less*	Capital contributions funding other reliability, safety and environment	–	
104		**Other reliability, safety and environment less capital contributions**		186
105				
106	**6a(ix): Non-Network Assets**			
107	**Routine expenditure**			
108		*Project or programme**	($000)	($000)
109				
110				
111				
112				
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116		**Routine expenditure**		–
117	**Atypical expenditure**			
118		*Project or programme**	($000)	($000)
119				
120				
121				
122				
123				
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure		
126		**Atypical expenditure**		–
127				
128		**Expenditure on non-network assets**		–

Company Name **Electricity Invercargill Limited**
For Year Ended **31 March 2020**

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

sch ref		($000)	($000)
7	**6b(i): Operational Expenditure**		
8	Service interruptions and emergencies	597	
9	Vegetation management	10	
10	Routine and corrective maintenance and inspection	1,358	
11	Asset replacement and renewal	106	
12	**Network opex**		2,070
13	System operations and network support	1,029	
14	Business support	2,046	
15	**Non-network opex**		3,075
16			
17	**Operational expenditure**		5,146
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		125
20	Direct billing*		–
21	Research and development		–
22	Insurance		135
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2020**

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 the ID determination), and so is subject to the assurance report required by section 2.8. For the purpose of this audit, target revenue and forecast expenditures only need to be verified back to previous disclosures.

sch ref		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	20,674	20,753	0%

sch ref		Forecast ($000) [2]	Actual ($000)	% variance
9	**7(ii): Expenditure on Assets**			
10	Consumer connection	419	519	24%
11	System growth		–	–
12	Asset replacement and renewal	5,123	3,955	(23%)
13	Asset relocations	6	–	(100%)
14	Reliability, safety and environment:			
15	Quality of supply	104	71	(32%)
16	Legislative and regulatory		–	–
17	Other reliability, safety and environment	224	186	(17%)
18	**Total reliability, safety and environment**	328	257	(22%)
19	**Expenditure on network assets**	5,876	4,730	(20%)
20	Expenditure on non-network assets		–	–
21	Expenditure on assets	5,876	4,730	(20%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	488	597	22%
24	Vegetation management	2	10	378%
25	Routine and corrective maintenance and inspection	1,044	1,358	30%
26	Asset replacement and renewal	211	106	(50%)
27	**Network opex**	1,745	2,070	19%
28	System operations and network support	1,177	1,029	(13%)
29	Business support	2,139	2,046	(4%)
30	**Non-network opex**	3,316	3,075	(7%)
31	**Operational expenditure**	5,061	5,146	2%
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	–	–	–
34	Overhead to underground conversion	–	–	–
35	Research and development	–	–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	125	125	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	277	135	(51%)

42

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

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

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Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2020
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

Billed quantities by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Price component: Variable day energy sales Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.): kWh	Variable day energy purchases KWh				
Low user	Residential	Standard	6,452	40,721		32,025,106				
Domestic	Residential	Standard	8,853	87,566		71,465,702				
Non-Domestic	Commerical	Standard	1,932	49,365		40,263,506				
Individual non half hour	Commerical	Standard	50	7,413		6,045,665				
Individual half hour	Commerical	Standard	124	66,776	48,003,913					
Add extra rows for additional consumer groups or price category codes as necessary										
		Standard consumer totals	17,411	251,841	48,003,913	149,799,978	–	–	–	–
		Non-standard consumer totals	–	–	–	–	–	–	–	–
		Total for all consumers	17,411	251,841	48,003,913	149,799,978	–	–	–	–

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Line charge revenues ($000) by price component					
						Price component	Variable day energy sales	Variable day energy purchases				
						Rate (eg, $ per day, $ per kWh, etc.)	kWh	KWh				
Low user	Residential	Standard	$3,968		$2,801	$1,167	$255	$3,713				
Domestic	Residential	Standard	$8,387		$5,920	$2,467	$3,046	$5,341				
Non-Domestic	Commerical	Standard	$4,967		$3,507	$1,461	$1,959	$3,009				
Individual non half hour	Commerical	Standard	$515		$325	$190	$64	$452				
Individual half hour	Commerical	Standard	$2,916		$1,596	$1,320	$1,466	$1,449				
		[Select one]	–									
		[Select one]	–									
		[Select one]	–									
		[Select one]	–									
		[Select one]	–									
		Standard consumer totals	$20,753	–	$14,149	$6,604	$6,789	$13,964	–	–	–	–
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	$20,753	–	$14,149	$6,604	$6,789	$13,964	–	–	–	–

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

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

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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 2020
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	721	748	27	3
10	All	Overhead Line	Wood poles	No.	225	218	(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	14	14	–	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.	2	2	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	16	14	(2)	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	5	5	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	2	1	(1)	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	50	48	(2)	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.	6	6	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	23	23	0	3
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	54	59	4	3
39	HV	Distribution Cable	Distribution UG PILC	km	99	97	(2)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	2	2	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	61	59	(2)	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	50	48	(2)	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	456	447	(9)	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	10	10	–	4
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	429	415	(14)	4
48	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	N/A
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	43	43	–	3
50	LV	LV Line	LV OH Conductor	km	30	30	0	3
51	LV	LV Cable	LV UG Cable	km	423	422	(1)	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	167	168	1	3
53	LV	Connections	OH/UG consumer service connections	No.	17,840	17,814	(26)	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	167	168	1	4
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	1	1	–	4
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

pwc

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2020
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

8 **Disclosure Year (year ended)** 31 March 2020

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	–	–	–	354	6	–	2	2	13	2	–	6	3	3	2	11	5	17	99	34	74	17	23	26	29	8	9	–	–	–	–	–	–	3	748	–	3
11	All	Overhead Line	Wood poles	No.	–	–	–	163	1	–	3	11	12	5	7	6	4	2	1	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	1	218	–	3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	–	0	–	–	1	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	1	–	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	5	1	4	–	–	–	–	–	–	–	0	–	–	–	–	–	–	4	–	–	–	–	–	–	–	–	–	–	–	14	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	5	7	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	12	–	3
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	1	1	1	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	5	–	4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	8	1	–	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	3	–	–	–	–	–	–	–	–	–	–	–	14	–	4
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	5	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	4	11	11	–	1	–	–	1	–	–	–	–	–	1	–	–	–	1	1	17	–	–	–	–	–	–	–	–	–	–	–	48	–	4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	1	1	1	–	–	–	1	–	–	–	–	–	–	–	–	–	1	1	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	0	–	0	12	5	2	3	1	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	1	0	–	–	–	–	–	–	–	–	0	23	–	3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0	–	–	0	1	1	2	5	9	6	1	2	3	1	3	2	5	2	2	1	2	0	4	3	1	0	2	0	–	–	–	–	–	1	59	–	3
40	HV	Distribution Cable	Distribution UG PILC	km	0	–	1	14	24	33	19	2	2	–	0	–	1	–	0	2	–	–	–	–	–	0	–	–	–	–	0	–	–	–	–	–	–	0	97	–	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	2	–	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	7	1	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	4	10	17	8	10	–	–	–	–	–	–	–	59	–	4
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	2	8	2	3	–	–	1	1	1	–	–	1	–	1	1	1	3	–	2	–	4	3	3	6	1	–	–	–	–	–	–	4	48	–	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	15	38	123	54	12	17	17	5	7	15	7	15	24	17	10	12	5	5	4	10	10	11	8	6	–	–	–	–	–	–	–	447	–	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	1	2	1	–	–	–	1	1	–	–	–	1	–	1	1	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	10	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	7	30	30	62	69	7	12	15	10	8	15	11	9	10	13	15	20	19	9	14	11	6	6	3	4	–	–	–	–	–	–	–	415	–	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	3	9	2	14	5	1	2	–	1	–	1	1	1	–	–	–	2	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	43	–	2
51	LV	LV Line	LV OH Conductor	km	–	–	0	3	0	2	1	16	–	3	1	0	0	0	–	0	–	–	0	0	0	0	0	0	0	0	0	–	–	–	–	–	–	0	30	–	3
52	LV	LV Cable	LV UG Cable	km	1	–	9	47	74	111	64	12	16	21	3	10	6	7	4	7	6	3	5	2	1	1	2	3	4	2	2	–	–	–	–	–	–	1	422	–	3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	2	0	1	15	5	22	88	19	2	1	0	0	1	0	1	2	1	1	1	0	2	1	0	1	0	0	0	–	–	–	–	–	–	2	168	–	3
54	LV	Connections	OH/UG consumer service connections	No.		3	114	2,236	3,987	3,626	5,493	41	54	61	199	259	280	201	211	131	100	105	97	84	60	63	77	86	62	53	73	13	–	–	–	–	–	45	17,814	–	2
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	34	31	39	1	4	–	–	1	–	–	–	–	–	–	–	–	–	–	1	30	11	4	5	7	–	–	–	–	–	–	–	168	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	Lot	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	4
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

pwc

Company Name	**Electricity Invercargill Limited**
For Year Ended	**31 March 2020**
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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	–	–	–
13	33kV	1	26	28
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	–	–	–
16	6.6kV to 11kV (inclusive—other than SWER)	23	156	179
17	Low voltage (< 1kV)	30	422	452
18	**Total circuit length (for supply)**	54	604	658
19				
20	Dedicated street lighting circuit length (km)	25	142	168
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			–
22				
23	**Overhead circuit length by terrain (at year end)**	**Circuit length (km)**	**(% of total overhead length)**	
24	Urban	51	93%	
25	Rural	2	3%	
26	Remote only	–	–	
27	Rugged only	2	4%	
28	Remote and rugged	–	–	
29	Unallocated overhead lines	–	–	
30	**Total overhead length**	54	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	658	100%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	4	7%	

Company Name **Electricity Invercargill Limited**
For Year Ended **31 March 2020**

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 *	Number of ICPs served	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 2020**
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref			
8	**9e(i): Consumer Connections**		
9	*Number of ICPs connected in year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Domestic	56	
12	Half Hour Individual	2	
13	Non Domestic	19	
14			
15			
16	** include additional rows if needed*		
17	**Connections total**	77	
18			
19	**Distributed generation**		
20	Number of connections made in year	14	**connections**
21	Capacity of distributed generation installed in year	0.10	**MVA**
22	**9e(ii): System Demand**		
23			
24		**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**		
26	GXP demand	62	
27	*plus* Distributed generation output at HV and above	–	
28	**Maximum coincident system demand**	62	
29	*less* Net transfers to (from) other EDBs at HV and above	(1.5)	
30	**Demand on system for supply to consumers' connection points**	63	
31	**Electricity volumes carried**	**Energy (GWh)**	
32	Electricity supplied from GXPs	253	
33	*less* Electricity exports to GXPs		
34	*plus* Electricity supplied from distributed generation	0.2	
35	*less* Net electricity supplied to (from) other EDBs	(14)	
36	**Electricity entering system for supply to consumers' connection points**	267	
37	*less* Total energy delivered to ICPs	252	
38	**Electricity losses (loss ratio)**	15	5.7%
39			
40	**Load factor**	0.48	
41	**9e(iii): Transformer Capacity**		
42		**(MVA)**	
43	Distribution transformer capacity (EDB owned)	150	
44	Distribution transformer capacity (Non-EDB owned, estimated)	2	
45	**Total distribution transformer capacity**	152	
46			
47	**Zone substation transformer capacity**	82	

Company Name	Electricity Invercargill Limited
For Year Ended	31 March 2020
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 the ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

8 10(i): Interruptions

sch ref	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	17
12	Class C (unplanned interruptions on the network)	33
13	Class D (unplanned interruptions by Transpower)	–
14	Class E (unplanned interruptions of EDB owned generation)	–
15	Class F (unplanned interruptions of generation owned by others)	–
16	Class G (unplanned interruptions caused by another disclosing entity)	2
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	52
20		

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	29	4
23			

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.05	13.1
27	Class C (unplanned interruptions on the network)	1.25	65.4
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	0.07	2.1
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	1.37	80.6
35			

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	1.30	78.6
38			

39 10(ii): Class C Interruptions and Duration by Cause

40

sch ref	Cause	SAIFI	SAIDI
42	Lightning	–	–
43	Vegetation	–	–
44	Adverse weather	0.05	1.7
45	Adverse environment	–	–
46	Third party interference	0.08	7.0
47	Wildlife	–	–
48	Human error	0.09	2.2
49	Defective equipment	1.01	52.9
50	Cause unknown	0.02	1.6
51			

52 10(iii): Class B Interruptions and Duration by Main Equipment Involved

53

sch ref	Main equipment involved	SAIFI	SAIDI
55	Subtransmission lines	–	–
56	Subtransmission cables	–	–
57	Subtransmission other	–	–
58	Distribution lines (excluding LV)	0.03	8.8
69	Distribution cables (excluding LV)	0.01	3.4
60	Distribution other (excluding LV)	0.01	0.9

61 10(iv): Class C Interruptions and Duration by Main Equipment Involved

62

sch ref	Main equipment involved	SAIFI	SAIDI
64	Subtransmission lines	–	–
65	Subtransmission cables	–	–
66	Subtransmission other	0.30	21.1
67	Distribution lines (excluding LV)	0.14	10.9
68	Distribution cables (excluding LV)	0.54	25.3
69	Distribution other (excluding LV)	0.27	8.1

70 10(v): Fault Rate

sch ref	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
72	Subtransmission lines	–	1.4	–
73	Subtransmission cables	–	26.2	–
74	Subtransmission other	1.0		
75	Distribution lines (excluding LV)	15.0	23.2	64.71
76	Distribution cables (excluding LV)	10.0	155.7	6.42
77	Distribution other (excluding LV)	7.0		
78	**Total**	33		

SCHEDULE 14 MANDATORY EXPLANATORY NOTES

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

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

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

Return on Investment (Schedule 2)

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

Box 1: Explanatory comment on return on investment

Electricity Invercargill Limited achieved a post-tax WACC of 6.94% which is above the 75th percentile estimate of post-tax WACC of 4.95% and a 7.37% vanilla WACC which is above with the 75th percentile estimate of vanilla WACC of 5.37%.

No items were reclassified.

Regulatory Profit (Schedule 3)

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

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

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

Box 2: Explanatory comment on regulatory profit

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

No items were reclassified in the disclosure year.

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

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

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

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

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

Value of the Regulatory Asset Base (Schedule 4)

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

Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)
The calculation of the Regulatory Asset Base (RAB) was stated using the 31 March 2019 closing figure of $86,605k as a starting point with inflationary indexing over the year to 31 March 2020 plus additions less disposals. This resulted in a closing RAB balance of $89,033k. 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 $144k 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)

Temporary differences are the tax effect of the difference between the tax and disclosure treatment of capital contribution income.

Taxable Capital Contributions:	$	80
	$	80
Tax Rate:		28%
Temporary Differences	$	22

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), all other costs are directly attributable as they were either passed through by PowerNet as agent or were invoiced to Electricity Invercargill Limited (no causal allocator is applicable and revenue has been used as a proxy allocator).

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 was no material atypical expenditure 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 13 and 14 above.

Capital Expenditure:
The actual expenditure on network assets was 20% below budget.

Consumer connection:

- Net 24% overspend due to customer driven delays in the new Kmart and Blue River Dairy connections (originally scheduled to be completed in the 2018/19 year).

System Growth:

- No spend in this category for FY19/20

Asset replacement and renewal:

- Net 23% underspend for FY19/20 largely due to delays in the Southern Sub project caused by issues with competitive tendering/access and customer associated easement delays for RMU replacement work.

Asset Relocations:

- 100% underspend as no customer initiated relocation requests were received for the year.

Quality of Supply:

- 32% underspend as no customer related power quality issues warranting network upgrade.

Reliability, Safety and Environment:

- 17% underspend due to difficulties accessing distribution earth sites for test and upgrade.

Operational Expenditure:
Network opex was 19% above budget.

Service interruptions and emergencies:

- 22% overspend due to due to to higher than average faults and fault response (see Box 13).

Vegetation management:

- Small reactive budget.

Routine and corrective maintenance and inspection:

- 30% overspend due to largely due to corrective action following distribution cable faults and cable termination faults.

Asset replacement and renewal:

- 50% underspend due to resource's being used for fault response and corrective maintenance work.

System Operations and Network Support:

- 13% underspent mainly due to the deferral of the proposed insurance captive for the network lines and cables.

Business Support:

- 4% underspend which is a minor variation representing $93k savings in operating expenditure during the year

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

Year ended 31 March 2020:

- Target revenue for the 2019-20 year was $20,674k. The total billed revenue for the 2019-20 year was $20,753k, which is $79k above.
- A cold wet summer caused additional consumption during this period resulting in the variable line charge being above budget.

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

The SAIDI assessed value for 2019/20 at 47.15, was above the applicable Commerce Commission Limit of 31.13, and above the Commerce Commission target level of 24.08.

The SAIFI assessed value for 2019/20 at 0.92, was above the applicable Commerce Commission Limit of 0.77, and above the Commerce Commission target level of 0.59.

However, in accordance with the Issues Register for Electricity and Gas Information Disclosure, issues 447 and 458, EIL has disclosed normalised SAIDI/SAIFI calculated according to the 2012 EDB ID while disclosing limits calculated according to the 2015 DPP.
EIL has disclosed a normalised SAIDI at 78.6 and normalised SAIFI at 1.3 for 2019/20.

2019/20 SAIDI and SAIFI were higher than the expected long term averages. Outages for 2019/20 were characterised by:

- high customer numbers impacted by third-party caused incidents
- high number of cable termination type failures due to external contractor work quality
- unusually high number of cable failures
- unusually high number of human error related trips
- high customer numbers impacted by a protection communications circuit failure to Southern Zone Substation that was difficult to diagnose, find, and repair

The information has been prepared on a basis consistent with the previous year's disclosure and EIL has recorded successive interruptions, originating from the same cause, as single interruptions.

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

Network reliability is compliant with quality requirements under the default price-quality path, however there are inherent limitations in the ability of Electricity Invercargill Limited to collect and record the network reliability information required to be disclosed in Reports 10(i) to 10(iv). Consequently there is no independent evidence available to support the accuracy of recorded faults and control over the accuracy of installation control point ('ICP') data, included in the SAIDI and SAIFI calculations, is limited throughout the year.

Insurance cover

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

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

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

Box 14: Explanation of insurance cover

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

- Substations and network equipment are insured for $27.1 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 Information

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

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

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

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

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

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

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

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

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

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

Nominal Prices are based on publicly available New Zealand Treasury's economic forecast indicated in the Half Year Economic and Fiscal Update (HYEFU) report released in December 2018:

	2020	2021	2022	2023	2024
Inflator (CAPEX & OPEX)	2.0%	2.0%	2.0%	2.0%	2.4%

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.)

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

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

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

2. Information in this schedule is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

4. APPENDIX - Related Party Transaction: Additional Information Disclosure

4.1 INTRODUCTION

For the purpose of meeting the 2020 Related Party Transaction reporting requirements, in accordance with section 2.3.6 of the Electricity Information Disclosure Determination 2012, (Consolidated in 2018), issued 3 April 2018.

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

- **Electricity Invercargill Limited's 2020 Information Disclosure**, for the year ended 31 March 2020 - 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's (EIL) being less than $20 million, for the year ending 31 March 2020.

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

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

4.3 RELATED PARTY RELATIONSHIPS

Electricity Invercargill Limited (EIL) has an interest in PowerNet Limited, the OtagoNet Joint Venture, Electricity Southland Limited, and the Southern Generation Limited Partnership through their wholly owned subsidiary company Pylon Limited. PowerNet Limited held an interest in PowerNet Central Limited. Following the acquisition of the remaining 10% shareholding, PowerNet Central was amalgamated with PowerNet Limited on 31 March 2020.

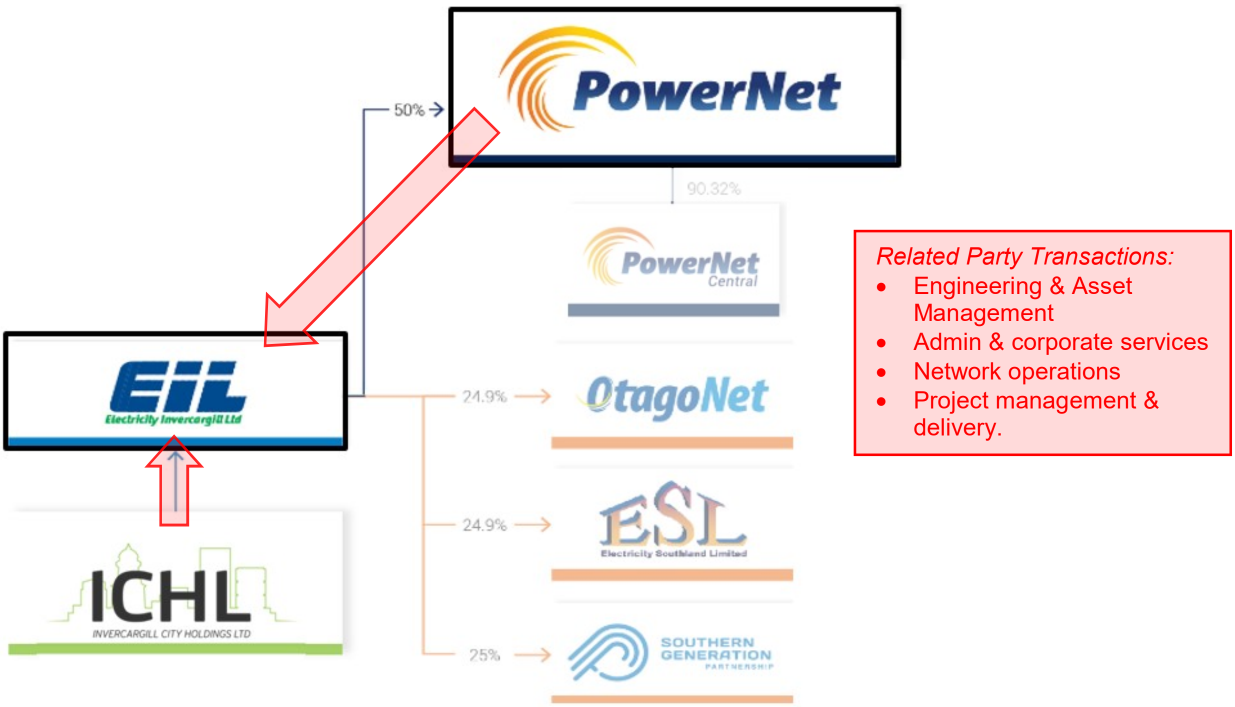
During the year ending 31 March 2020, EIL had related party transactions with the following entities:

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

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

Company Structure

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



a. PowerNet Limited

EIL holds a 50% shareholding in electricity network management company PowerNet Limited (PowerNet). PowerNet provides a range of field contracting, asset management, system control and finance and commercial services to EIL. The value of the related party transactions for the year ended 31 March 2020 is categorised as follows:

		($'000)
Operating Expenditure:		
i.	Service interruptions and emergencies	597
ii.	Vegetation management	10
iii.	Routine and corrective maintenance and inspection	1,358
iv.	Asset replacement and renewal (opex)	106
v.	System operations and network support	299
vi.	Business support	1,389
Capital Expenditure		
i.	Consumer connection	519
i.	System Growth	-
ii.	Asset replacement and renewal (capex)	3,955
iii.	Asset relocations	-
iv.	Quality of supply	71
v.	Other reliability, safety and environment	186
	Total Related Party expenditure from PowerNet	**8,489**

In the year to 31 March 2020, PowerNet provided 100% of the EIL Lines Business Capital Expenditure, and 78% of all Operating Expenditure. The high percentage of related party transactions relative to total expenditure is due to PowerNet operating under a Network Management Agreement (NMA) with EIL, in the form of an "agency agreement".

Services provided under the agreement include:

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

For the majority of the year, PowerNet held an ownership interest of approximately 90% in PowerNet Central Ltd (formerly Peak Power Services Ltd), a Central Otago based electricity distribution maintenance contracting business, servicing the Electricity Southland Ltd network assets. Following the acquisition of the remaining 10% shareholding, PowerNet Central was amalgamated with PowerNet Ltd on 31 March 2020.

b. Invercargill City Holdings Limited

EIL is owned 100% by Invercargill City Holdings Limited (ICHL). The role of ICHL is to provide governance, funding and treasury support to the subsidiary companies they own.
The value of the related party transactions between ICHL and EIL for the year ended 31 March 2020 is categorised as follows:

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

In the year to 31 March 2020, ICHL provided 8.9% of all Operating Expenditure relating to management fees.

Network Management Agreement

EIL incurs 100% of its capital expenditure and a high percentage of its operating costs for its electricity distribution and metering 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 a 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 Agency 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 2018 of the allocation methodology ensured all parties that are charged agency 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 (+/-13%) 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 at or above the same internal rates as charged to the EDB customers;
- Large percentage of Works Programme costs charged to EIL (almost 60% of Capital and Maintenance work) 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 THE COMMERCE COMMISSION

The Auditor-General is the auditor of Electricity Invercargill Limited (the company). The Auditor-General has appointed me, Nathan Wylie, using the staff and resources of PricewaterhouseCoopers, to provide an opinion, on his behalf, on:

- whether the information required to be disclosed in accordance with the Electricity Distribution Information Disclosure Determination 2012 as amended by the Information Disclosure exemption: Disclosure and auditing of reliability information within schedule 10, issued by the Commerce Commission on 9 April 2020 (the 'Determination, as amended') for the disclosure year ended 31 March 2020, have been prepared, in all material respects, in accordance with the Determination, as amended.

  The disclosure information required to be reported by the Company, and audited by the Auditor-General under the Determination, as amended, is in schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10, and the explanatory notes in boxes 1 to 11 in Schedule 14 ('the Disclosure Information').

- whether the Company's basis for valuation of related party transactions ('the Related Party Transaction Information') for the disclosure year ended 31 March 2020, has been prepared, in all material respects, in accordance with clause 2.3.6 of the Determination, as amended, and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 ('the Input Methodologies Determination').

Qualified Opinion

In our opinion, except for the possible effect of the matter described in the Basis for qualified opinion section of our report:

- as far as appears from an examination of them, proper records to enable the complete and accurate compilation of the Disclosure Information have been kept by the Company;
- as far as appears from an examination, the information used in the preparation of the Disclosure Information has been properly extracted from the company's accounting and other records and has been sourced, where appropriate, from the Company's financial and non-financial systems;
- the Disclosure Information complies, in all material respects, with the Determination, as amended; and
- the Related Party Transaction Information complies, in all material respects, with the Determination, as amended and the Input Methodologies Determination.

In forming our qualified opinion, except as explained in the Basis for qualified opinion section of our report, we have obtained sufficient recorded evidence and all the information and explanations we have required.

Basis of qualified opinion

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

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There are no practical audit procedures that we could adopt to independently confirm the accuracy of the ICP data used to record the number of ICP's affected and duration of the interruption for the purposes of inclusion in the amounts relating to SAIDI and SAIFI outage statistics set out in Schedules 10(i) to 10(iv). Because of the potential effect of the limitations described above, we are unable to form an opinion as to the accuracy of the data that forms the basis of the compilation of Schedules 10(i) to 10(iv). In this respect alone we have not obtained all the recorded evidence and explanations that we have required.

We 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* and the Standard on Assurance Engagements 3100 (Revised): *Assurance Engagements on Compliance* issued by the New Zealand Auditing and Assurance Standards Board. Copies of these standards are available on the External Reporting Board's website.

These standards require that we comply with ethical requirements and plan and perform our assurance engagement to provide reasonable assurance about whether the Disclosure Information has been prepared, in all material respects, with the Determination, as amended and about whether the Related Party Transaction Information has been prepared, in all material respects, with the Determination, as amended and the Input Methodologies Determination. Reasonable assurance is a high level of assurance.

We have performed procedures to obtain evidence about the amounts and disclosures in the Disclosure Information, and the basis of valuation in the Related Party Transaction Information. The procedures selected depend on our judgement, including the assessment of the risks of material misstatement of the Disclosure Information and the Related Party Transaction Information, whether due to fraud or error or non-compliance with the Determination, as amended or the Input Methodologies Determination. In making those risk assessments, we considered internal control relevant to the Company's preparation of the Disclosure Information and the Related Party Transaction Information in order to design procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

Scope and inherent limitations

Because of the inherent limitations of a reasonable assurance engagement, and the test basis of the procedures performed, it is possible that fraud, error or non-compliance may occur and not be detected.

We did not examine every transaction, adjustment or event underlying the Disclosure Information or the Related Party Transaction Information, nor do we guarantee complete accuracy of the Disclosure Information or the Related Party Transaction Information. Also we did not evaluate the security and controls over the electronic publication of the Disclosure Information or the Related Party Transaction Information.

The qualified opinion expressed in this independent assurance report has been formed on the above basis.

Key Assurance Matters

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

Key assurance matter	How our procedures addressed the key assurance matter
Regulatory Asset Base The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of the Company's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination, as amended. It is a measure which is used widely and is key to measuring the Company's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the Input Methodologies, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration. Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination, as amended and the Input Methodologies (IMs). We have performed the following procedures: *Assets commissioned* • We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions disclosed in the audited annual financial statements and investigated any reconciling items; • We inspected the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, as amended which are required to be removed from the RAB; • We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification; *Depreciation* • We compared the standard asset lives by asset category to those set out in the IMs; • We verified the spreadsheet formula utilised to calculate regulatory depreciation expense is in line with IM clause 2.2.5; *Revaluation* • We recalculated the revaluation rate set out in the Input Methodologies using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; • We tested the mathematical accuracy of the revaluation calculation performed by management; *Disposals* • We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the IMs. We have no matters to report from undertaking those procedures.

Key assurance matter	How our procedures addressed the key assurance matter
Related party transactions Disclosures over related party transactions as required under the Determination, as amended and the Input Methodologies are set out in Appendix A. The Determination, as amended and the Input Methodologies require the Company to value its transactions with related parties, disclosed in Schedule 5b, in accordance with the principles-based approach to the arm's length valuation rule. This rule states that the value of goods or services acquired from a related party cannot be greater than if it had been acquired under the terms of an arm's length transaction with an unrelated party, nor may it exceed the actual cost to the related party. A sale or supply to a related party cannot be valued at an amount less than if it had been sold or supplied under the terms of an arm's-length transaction with an unrelated party. Arm's-length valuation, as defined in the Input Methodologies, 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. The Company is required to use an objective and independent measure to demonstrate compliance with the arm's-length principle. In the absence of an active market for similar transactions, assigning an objective arm's length value to a related party transaction is difficult and requires significant judgement. We have identified related party transactions at arm's-length as a key audit matter due to the judgement involved.	We have obtained an understanding of the compliance requirements relevant to related party transactions as set out in the Determination, as amended, and the Input Methodologies. We have ensured Schedule 5(b) and Appendix A includes all required disclosures as appropriate for an EDB required to make limited disclosure. We have performed the following procedures over Schedule 5(b) and Appendix A. *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 2020 and to the accounting records, investigating any differences and determining whether any such differences are justified; and • Applying our understanding of the business structure against the related party definition in Input Methodologies Determination clause 1.1.4(2)(b) to assess management's identification of any "unregulated parts" of the entity. *Arm's length valuation rule* We obtained the Company's assessment of the available independent and objective measures used in supporting the arm's length valuation principle and performed the following procedures: • Re-performed the calculations 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 an acceptable range. Qualitative factors were considered in determining the appropriate acceptable range. We have no matters to report from undertaking those procedures.

Directors' responsibility for the preparation of the Disclosure Information and the Related Party Information

The directors of the Company are responsible for:

- the preparation of the Disclosure Information in accordance with the Determination, as amended, and
- the Related Party Transaction Information in accordance with the Determination, as amended and the Input Methodologies Determination

and for such internal control as the directors determine is necessary to enable the preparation of the Disclosure Information and the Related Party Transaction Information that is free from material misstatement.

Our responsibility for the Disclosure Information and the Related Party Information

Our responsibility is to express an opinion on whether:

- the Disclosure Information has been prepared, in all material respects, in accordance with the Determination, as amended; and
- the Related Party Transaction Information has been prepared, in all material respects, in accordance with the Determination, as amended and the Input Methodologies Determination.

Independence and quality control

When carrying out the engagement, we complied with:

- the Auditor-General's independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 (Revised) issued by the New Zealand Auditing and Assurance Standards Board;
- the independence requirements specified in the Determination, as amended; and
- the Auditor-General's quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

The Auditor-General, and his employees, and PricewaterhouseCoopers and its partners and employees may deal with the Company on normal terms within the ordinary course of trading activities of the Company. Other than any dealings on normal terms within the ordinary course of business, this engagement, engagements in the areas of compliance with the Electricity Distribution Services Default Price-Quality Path Determination 2015 and other regulatory requirements of the Commerce Act 1986, as well as regulatory advisory services which are compatible with those independent requirements and the annual audit of the Company's financial statements, we have no relationship with or interests in the Company.

Use of this report

This independent assurance report has been prepared solely for the directors of the Company and for the Commerce Commission for the purpose of providing those parties with reasonable assurance about whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination, as amended and whether the Related Party Transaction Information has been prepared, in all material respects, in accordance with the Determination, as amended and the Input Methodologies Determination. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the Company or the Commerce Commission, or for any other purpose than that for which it was prepared.

Nathan Wylie
PricewaterhouseCoopers
On behalf of the Auditor-General
Christchurch, New Zealand
27 August 2020

6. DIRECTORS' CERTIFICATE

Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Thomas Campbell and Sarah Jane Brown, being directors of Electricity Invercargill Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

a) the information prepared for the purposes of clauses 2.3.1, 2.3.2, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.7.1 of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination; and

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

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

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

   ii. the value of assets or goods or services sold or supplied to a related party comply, in all material respects, with clause 2.3.6(2) of the Electricity Distribution Information Disclosure Determination 2012.

Thomas Campbell **Sarah Jane Brown**

27 August 2020

Footnote:
The Directors of Electricity Invercargill Limited (EIL) note the amendment in respect to the Information Disclosure Exemption: Disclosure and auditing or reliability information within schedule 10, issued by the Commerce Commission on 9 April 2020 that has removed the auditor report requirements relating to the treatment of successive interruptions for reporting SAIDI, SAIFI, and interruptions, because of potential inconsistencies in treatment approaches across the industry.

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