OtagoNet Joint Venture

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

For the Year Ended 31 March 2023

CONTENTS

1. INTRODUCTION

These Information Disclosure documents are submitted by OtagoNet Joint Venture pursuant to Part 4 of the Commerce Act 1986 in accordance with:

- The Electricity Information Disclosure Determination 2012 (consolidated in 2023), issued 6 July 2023,
- The Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 2020), issued 20 May 2020.

2. INFORMATION DISCLOSURE DISCLAIMER

The information disclosed in this Information Disclosure package issued by OtagoNet Joint Venture 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	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**

SCHEDULE 1: ANALYTICAL RATIOS

This schedule calculates expenditure, revenue and service ratios from the information disclosed. The disclosed ratios may vary for reasons that are company specific and, as a result, must be interpreted with care. The Commerce Commission will publish a summary and analysis of information disclosed in accordance with this ID determination. This will include information disclosed in accordance with this and other schedules, and information disclosed under the other requirements of this determination.

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

sch ref

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**	21,686	518	137,564	2,172	42,476
10	Network	13,429	321	85,186	1,345	26,303
11	Non-network	8,257	197	52,379	827	16,173
12						
13	**Expenditure on assets**	43,569	1,041	276,376	4,363	85,337
14	Network	43,569	1,041	276,376	4,363	85,337
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**	70,645	1,688
20	Standard consumer line charge revenue	111,221	1,517
21	Non-standard consumer line charge revenue	16,692	1,104,633
22			

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

sch ref			
24			
25	Demand density	16	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	100	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27	Connection point density	4	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28	Energy intensity	23,889	*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	10,030	30.78%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	8,683	26.64%
34	Total depreciation	9,688	29.72%
35	Total revaluations	15,995	49.08%
36	Regulatory tax allowance	874	2.68%
37	Regulatory profit/(loss) including financial incentives and wash-ups	19,311	59.25%
38	**Total regulatory income**	32,591	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	20.98	*Interruptions per 100 circuit km*

Company Name **OtagoNet Joint Venture**
For Year Ended **31 March 2023**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

sch ref		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8		31 Mar 21	31 Mar 22	31 Mar 23
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	4.38%	9.72%	8.16%
11	Excluding revenue earned from financial incentives	4.41%	10.34%	8.92%
12	Excluding revenue earned from financial incentives and wash-ups	4.41%	10.42%	9.00%
13				
14	**Mid-point estimate of post tax WACC**	3.72%	3.52%	4.88%
15	25th percentile estimate	3.04%	2.84%	4.20%
16	75th percentile estimate	4.40%	4.20%	5.56%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	4.71%	10.02%	8.67%
21	Excluding revenue earned from financial incentives	4.74%	10.64%	9.44%
22	Excluding revenue earned from financial incentives and wash-ups	4.74%	10.72%	9.52%
23				
24	**WACC rate used to set regulatory price path**	4.57%	4.57%	4.57%
25				
26	**Mid-point estimate of vanilla WACC**	4.05%	3.82%	5.39%
27	25th percentile estimate	3.37%	3.14%	4.71%
28	75th percentile estimate	4.73%	4.50%	6.07%
29				
30	**2(ii): Information Supporting the ROI**		($000)	
31				
32	Total opening RAB value	240,495		
33	*plus* Opening deferred tax	(21,664)		
34	**Opening RIV**		218,831	
35				
36	**Line charge revenue**		32,674	
37				
38	Expenses cash outflow	18,713		
39	*add* Assets commissioned	16,920		
40	*less* Asset disposals	105		
41	*add* Tax payments	(1,389)		
42	*less* Other regulated income	(83)		
43	**Mid-year net cash outflows**		34,222	
44				
45	**Term credit spread differential allowance**		–	
46				
47	Total closing RAB value	263,617		
48	*less* Adjustment resulting from asset allocation	(0)		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(23,927)		
51	**Closing RIV**		239,691	
52				
53	**ROI – comparable to a vanilla WACC**			8.67%
54				
55	Leverage (%)			42%
56	Cost of debt assumption (%)			4.38%
57	Corporate tax rate (%)			28%
58				
59	**ROI – comparable to a post tax WACC**			8.16%
60				

2(iii): Information Supporting the Monthly ROI

Opening RIV	N/A

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

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

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

Year-end ROI – comparable to a vanilla WACC	9.60%
Year-end ROI – comparable to a post tax WACC	9.09%

** 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	(2,110)	
Purchased assets – avoided transmission charge	–	
Energy efficiency and demand incentive allowance		
Quality incentive adjustment	(176)	
Other financial incentives	–	
Financial incentives		(2,286)
Impact of financial incentives on ROI		–0.76%
Input methodology claw-back	–	
CPP application recoverable costs	–	
Catastrophic event allowance	–	
Capex wash-up adjustment	(228)	
Transmission asset wash-up adjustment	–	
2013–15 NPV wash-up allowance	–	
Reconsideration event allowance	–	
Other wash-ups	–	
Wash-up costs		(228)
Impact of wash-up costs on ROI		–0.08%

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**

SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref				
7		**3(i): Regulatory Profit**		**($000)**
8		**Income**		
9		Line charge revenue		32,674
10	*plus*	Gains / (losses) on asset disposals		(83)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)		–
12				
13		**Total regulatory income**		32,591
14		**Expenses**		
15	*less*	Operational expenditure		10,030
16				
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups		8,683
18				
19		**Operating surplus / (deficit)**		13,878
20				
21	*less*	Total depreciation		9,688
22				
23	*plus*	Total revaluations		15,995
24				
25		**Regulatory profit / (loss) before tax**		20,185
26				
27	*less*	Term credit spread differential allowance		–
28				
29	*less*	Regulatory tax allowance		874
30				
31		**Regulatory profit/(loss) including financial incentives and wash-ups**		19,311
32				
33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	183	
36		Commerce Act levies	94	
37		Industry levies	94	
38		CPP specified pass through costs	–	
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	7,190	
41		Transpower new investment contract charges	208	
42		System operator services	–	
43		Distributed generation allowance	914	
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**		8,683
47				
48		**3(iii): Incremental Rolling Incentive Scheme**	**($000)**	
49			**CY-1**	**CY**
50			**31 Mar 22**	**31 Mar 23**
51		Allowed controllable opex	–	–
52		Actual controllable opex	–	–
53				
54		Incremental change in year		–
55				
56			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
57		CY-5 [year]	–	–
58		CY-4 [year]	–	–
59		CY-3 [year]	–	–
60		CY-2 [year]	–	–
61		CY-1 [year]	–	–
62		**Net incremental rolling incentive scheme**		–
63				
64		**Net recoverable costs allowed under incremental rolling incentive scheme**		–
65		**3(iv): Merger and Acquisition Expenditure**		
70				**($000)**
66		Merger and acquisition expenditure		–
67				
68		*Provide commentary on the benefits of merger and acquisition expenditure to the electricity distribution business, including required disclosures in accordance with section 2.7, in Schedule 14 (Mandatory Explanatory Notes)*		
69		**3(v): Other Disclosures**		
70				**($000)**
71		Self-insurance allowance		–

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2023

SCHEDULE 4: REPORT ON VALUE OF THE REGULATORY ASSET BASE (ROLLED FORWARD)

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

sch ref

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

	RAB 31 Mar 19 ($000)	RAB 31 Mar 20 ($000)	RAB 31 Mar 21 ($000)	RAB 31 Mar 22 ($000)	RAB 31 Mar 23 ($000)
Total opening RAB value	186,531	194,442	210,599	217,608	240,495
less **Total depreciation**	7,712	7,994	8,588	8,881	9,688
plus **Total revaluations**	2,766	4,923	3,202	15,060	15,995
plus **Assets commissioned**	12,937	19,339	12,425	16,874	16,920
less **Asset disposals**	80	111	30	165	105
plus **Lost and found assets adjustment**	–	–	–	–	–
plus **Adjustment resulting from asset allocation**	–	–	–	–	(0)
Total closing RAB value	194,442	210,599	217,608	240,495	263,617

4(ii): Unallocated Regulatory Asset Base

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Total opening RAB value		240,495		240,495
less				
Total depreciation		9,688		9,688
plus				
Total revaluations		15,995		15,995
plus				
Assets commissioned (other than below)	–		–	
Assets acquired from a regulated supplier	–		–	
Assets acquired from a related party	16,920		16,920	
Assets commissioned		16,920		16,920
less				
Asset disposals (other than below)	105		105	
Asset disposals to a regulated supplier	–		–	
Asset disposals to a related party	–		–	
Asset disposals		105		105
plus **Lost and found assets adjustment**		–		–
plus **Adjustment resulting from asset allocation**				(0)
Total closing RAB value		263,617		263,617

** The 'unallocated RAB' is the total value of those assets used wholly or partially to provide electricity distribution services without any allowance being made for the allocation of costs to services provided by the supplier that are not electricity distribution services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.*

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

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

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Total opening RAB value	240,495		240,495	
less Opening value of fully depreciated, disposed and lost assets	146		146	
Total opening RAB value subject to revaluation	240,349		240,349	
Total revaluations		15,995		15,995

4(iv): Roll Forward of Works Under Construction

	Unallocated works under construction		Allocated works under construction	
Works under construction—preceding disclosure year		6,379		6,379
plus Capital expenditure	18,085		18,085	
less Assets commissioned	16,920		16,920	
plus Adjustment resulting from asset allocation			–	
Works under construction - current disclosure year		7,544		7,544
Highest rate of capitalised finance applied				–

4(v): Regulatory Depreciation

	Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
Depreciation - standard	9,688		9,688	
Depreciation - no standard life assets	–		–	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		9,688		9,688

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	29,333	3,086	36,969	109,250	16,731	24,953	14,456	4,515	1,202	240,495
less	Total depreciation	1,426	69	1,712	4,355	381	898	662	149	35	9,688
plus	Total revaluations	1,952	205	2,457	7,269	1,113	1,656	962	300	80	15,995
plus	Assets commissioned	2,384	–	1,311	6,279	3,444	1,054	1,949	499	–	16,920
less	Asset disposals	–	–	42	–	–	63	–	–	–	105
plus	Lost and found assets adjustment	–	–	–	–	–	–	–	–		–
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–		–
plus	Asset category transfers	–	–	–	–	–	–	–	–		–
	Total closing RAB value	32,243	3,223	38,982	118,443	20,907	26,702	16,705	5,165	1,247	263,617

Asset Life

	Subtransmission lines	Subtransmission cables	Zone substations	Distribution and LV lines	Distribution and LV cables	Distribution substations and transformers	Distribution switchgear	Other network assets	Non-network assets	
Weighted average remaining asset life	35.6	44.8	39.0	31.5	44.7	29.7	27.2	30.5	19.2	(years)
Weighted average expected total asset life	56.0	49.4	51.0	57.3	50.3	49.9	39.0	40.9	34.7	(years)

Company Name	**OtagoNet Joint Venture**
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SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

This schedule requires information on the calculation of the regulatory tax allowance. This information is used to calculate regulatory profit/loss in Schedule 3 (regulatory profit). EDBs must provide explanatory commentary on the information disclosed in this schedule, in Schedule 14 (Mandatory Explanatory Notes).
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref					
7	**5a(i): Regulatory Tax Allowance**			**($000)**	
8		**Regulatory profit / (loss) before tax**		20,185	
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	1,330		
13		Amortisation of revaluations	1,590		
14				2,920	
15					
16	*less*	Total revaluations	15,995		
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	48		*
20		Notional deductible interest	3,940		
21				19,983	
22					
23		**Regulatory taxable income**		3,122	
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		3,122	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		874	
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	23,941		
37	*less*	Amortisation of initial differences in asset values	1,330		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	51		
40		Closing unamortised initial differences in asset values		22,560	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		18	
43					

pwc

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	204,280	
	Adjusted depreciation	8,098	
	Total depreciation	9,688	
	Amortisation of revaluations		1,590

5a(v): Reconciliation of Tax Losses

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

5a(vi): Calculation of Deferred Tax Balance

			($000)
	Opening deferred tax	(21,664)	
plus	Tax effect of adjusted depreciation	2,267	
less	Tax effect of tax depreciation	4,459	
plus	Tax effect of other temporary differences*	316	
less	Tax effect of amortisation of initial differences in asset values	372	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–	
less	Deferred tax balance relating to assets disposed in the disclosure year	15	
plus	Deferred tax cost allocation adjustment	0	
	Closing deferred tax		(23,927)

5a(vii): Disclosure of Temporary Differences

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

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

			($000)
	Opening sum of regulatory tax asset values	99,128	
less	Tax depreciation	15,924	
plus	Regulatory tax asset value of assets commissioned	18,350	
less	Regulatory tax asset value of asset disposals	80	
plus	Lost and found assets adjustment	–	
plus	Adjustment resulting from asset allocation	–	
plus	Other adjustments to the RAB tax value	–	
	Closing sum of regulatory tax asset values		101,474

Company Name	**OtagoNet Joint Venture**
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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 this ID determination.
This information is part of audited disclosure information (as defined in clause 1.4 of this ID determination), and so is subject to the assurance report required by clause 2.8.

sch ref

5b(i): Summary—Related Party Transactions

	($000)	($000)
Total regulatory income		–
Market value of asset disposals		–
Service interruptions and emergencies	2,292	
Vegetation management	906	
Routine and corrective maintenance and inspection	2,833	
Asset replacement and renewal (opex)	180	
Network opex		6,211
Business support	1,882	
System operations and network support	854	
Operational expenditure		8,947
Consumer connection	7,426	
System growth	1,020	
Asset replacement and renewal (capex)	10,405	
Asset relocations	383	
Quality of supply	195	
Legislative and regulatory	–	
Other reliability, safety and environment	722	
Expenditure on non-network assets		–
Expenditure on assets		20,151
Cost of financing		–
Value of capital contributions		–
Value of vested assets		–
Capital Expenditure		20,151
Total expenditure		29,098
Other related party transactions		–

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

Name of related party	Nature of opex or capex service provided	Total value of transactions ($000)
The Power Company Limited	System operations and network support	60
PowerNet Limited	Service interruptions and emergencies	2,292
PowerNet Limited	Vegetation management	906
PowerNet Limited	Routine and corrective maintenance and inspection	2,833
PowerNet Limited	Asset replacement and renewal (opex)	180
PowerNet Limited	System operations and network support	794
PowerNet Limited	Business support	1,882
PowerNet Limited	Consumer connection	7,426
PowerNet Limited	System growth	1,020
PowerNet Limited	Asset replacement and renewal (capex)	10,405
PowerNet Limited	Asset relocations	383
PowerNet Limited	Quality of supply	195
PowerNet Limited	Other reliability, safety and environment	722
Total value of related party transactions		29,098

** include additional rows if needed*

Company Name	**OtagoNet Joint Venture**
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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 this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref

7

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

9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
10									
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: OtagoNet Joint Venture
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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 this ID determination), and so is subject to the assurance report required by section 2.8.

5d(i): Operating Cost Allocations

sch ref		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
8		Value allocated ($000s)				
10	**Service interruptions and emergencies**					
11	Directly attributable		2,292			
12	Not directly attributable				–	
13	**Total attributable to regulated service**		2,292			
14	**Vegetation management**					
15	Directly attributable		906			
16	Not directly attributable				–	
17	**Total attributable to regulated service**		906			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		2,833			
20	Not directly attributable				–	
21	**Total attributable to regulated service**		2,833			
22	**Asset replacement and renewal**					
23	Directly attributable		180			
24	Not directly attributable				–	
25	**Total attributable to regulated service**		180			
26	**System operations and network support**					
27	Directly attributable		1,389			
28	Not directly attributable				–	
29	**Total attributable to regulated service**		1,389			
30	**Business support**					
31	Directly attributable		2,430			
32	Not directly attributable				–	
33	**Total attributable to regulated service**		2,430			
35	**Operating costs directly attributable**		10,030			
36	**Operating costs not directly attributable**	–	–	–	–	–
37	**Operational expenditure**		10,030			

5d(ii): Other Cost Allocations

sch ref		($000)
40	**Pass through and recoverable costs**	
41	**Pass through costs**	
42	Directly attributable	371
43	Not directly attributable	–
44	**Total attributable to regulated service**	371
45	**Recoverable costs**	
46	Directly attributable	8,312
47	Not directly attributable	–
48	**Total attributable to regulated service**	8,312

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

sch ref				($000) CY-1	Current Year (CY)
52	**Change in cost allocation 1**				
53	Cost category		Original allocation	–	–
54	Original allocator or line items		New allocation	–	–
55	New allocator or line items		Difference	–	–
57	Rationale for change				
61	**Change in cost allocation 2**				
62	Cost category		Original allocation	–	–
63	Original allocator or line items		New allocation	–	–
64	New allocator or line items		Difference	–	–
66	Rationale for change				
70	**Change in cost allocation 3**				
71	Cost category		Original allocation	–	–
72	Original allocator or line items		New allocation	–	–
73	New allocator or line items		Difference	–	–
75	Rationale for change				

78 ** 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.*
79 *† include additional rows if needed*

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	32,243
Not directly attributable	–
Total attributable to regulated service	32,243
Subtransmission cables	
Directly attributable	3,223
Not directly attributable	–
Total attributable to regulated service	3,223
Zone substations	
Directly attributable	38,982
Not directly attributable	–
Total attributable to regulated service	38,982
Distribution and LV lines	
Directly attributable	118,443
Not directly attributable	–
Total attributable to regulated service	118,443
Distribution and LV cables	
Directly attributable	20,907
Not directly attributable	–
Total attributable to regulated service	20,907
Distribution substations and transformers	
Directly attributable	26,702
Not directly attributable	–
Total attributable to regulated service	26,702
Distribution switchgear	
Directly attributable	16,705
Not directly attributable	–
Total attributable to regulated service	16,705
Other network assets	
Directly attributable	5,165
Not directly attributable	–
Total attributable to regulated service	5,165
Non-network assets	
Directly attributable	1,247
Not directly attributable	–
Total attributable to regulated service	1,247
Regulated service asset value directly attributable	263,617
Regulated service asset value not directly attributable	–
Total closing RAB value	263,617

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	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**

SCHEDULE 6a: REPORT ON CAPITAL EXPENDITURE FOR THE DISCLOSURE YEAR

This schedule requires a breakdown of capital expenditure on assets incurred in the disclosure year, including any assets in respect of which capital contributions are received, but excluding assets that are vested assets. Information on expenditure on assets must be provided on an accounting accruals basis and must exclude finance costs.
EDBs must provide explanatory comment on their expenditure on assets in Schedule 14 (Explanatory Notes to Templates).
This information is part of audited disclosure information (as defined in section 1.4 of this ID determination), and so is subject to the assurance report required by section 2.8.

sch ref				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		7,426
9		System growth		1,020
10		Asset replacement and renewal		10,405
11		Asset relocations		383
12		Reliability, safety and environment:		
13		Quality of supply	195	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	722	
16		**Total reliability, safety and environment**		917
17		**Expenditure on network assets**		20,151
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		20,151
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		2,066
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		18,085
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		–
28		Overhead to underground conversion		
29		Research and development		–
		Cybersecurity (Commission only)		–
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Customer Connections < 20 kVA	1,160	
33		Customer Connections 21 - 99 kVA	245	
34		Customer Connections > 100 kVA	268	
35		New Subdivisions	5,753	
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		7,426
39				
40	*less*	Capital contributions funding consumer connection expenditure	1,273	
41		**Consumer connection less capital contributions**		6,153
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement**
43			**System Growth**	**and Renewal**
44			**($000)**	**($000)**
45		Subtransmission	–	2,206
46		Zone substations	–	994
47		Distribution and LV lines	2	6,375
48		Distribution and LV cables	1,018	38
49		Distribution substations and transformers	–	327
50		Distribution switchgear	–	465
51		Other network assets	–	0
52		**System growth and asset replacement and renewal expenditure**	1,020	10,405
53	*less*	Capital contributions funding system growth and asset replacement and renewal	–	2
54		**System growth and asset replacement and renewal less capital contributions**	1,020	10,403
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Asset Relocation	383	
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	–	
65		**Asset relocations expenditure**		383
66	*less*	Capital contributions funding asset relocations	791	
67		**Asset relocations less capital contributions**		(408)

68				
69		**6a(vi): Quality of Supply**		
70		*Project or programme**	($000)	($000)
71		Finegand 33kV Smart Network Automation	36	
72		Network Improvement Projects	57	
73		Mobile substation Site Made Ready	19	
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply	83	
78		**Quality of supply expenditure**		195
79	*less*	Capital contributions funding quality of supply	–	
80		**Quality of supply less capital contributions**		195
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		Substation NER`s and 33kV Transformer Circuit Breakers	262	
96		Replacement of OH Structures with Ground Mounted	34	
97		Earth Refurbishment	152	
98		Clydevale 33 kV Ring Rebuild and Protection	133	
99				
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment	141	
102		**Other reliability, safety and environment expenditure**		722
103	*less*	Capital contributions funding other reliability, safety and environment	–	
104		**Other reliability, safety and environment less capital contributions**		722
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	OtagoNet Joint Venture
For Year Ended	31 March 2023

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	2,292	
9	Vegetation management	906	
10	Routine and corrective maintenance and inspection	2,833	
11	Asset replacement and renewal	180	
12	**Network opex**		6,211
13	System operations and network support	1,389	
14	Business support	2,430	
15	**Non-network opex**		3,819
16			
17	**Operational expenditure**		10,030
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	*EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*		
20	Energy efficiency and demand side management, reduction of energy losses		–
21	Direct billing*		–
22	Research and development		–
23	Insurance		222
24	Cybersecurity (Commission only)		–
25	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	32,428	32,674	1%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	5,019	7,426	48%
11	System growth	865	1,020	18%
12	Asset replacement and renewal	8,605	10,405	21%
13	Asset relocations	34	383	1,026%
14	Reliability, safety and environment:			
15	Quality of supply	293	195	(33%)
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	997	722	(28%)
18	**Total reliability, safety and environment**	1,290	917	(29%)
19	**Expenditure on network assets**	15,813	20,151	27%
20	Expenditure on non-network assets	36	–	(100%)
21	Expenditure on assets	15,849	20,151	27%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	2,186	2,292	5%
24	Vegetation management	978	906	(7%)
25	Routine and corrective maintenance and inspection	1,811	2,833	56%
26	Asset replacement and renewal	165	180	9%
27	**Network opex**	5,140	6,211	21%
28	System operations and network support	1,355	1,389	3%
29	Business support	2,166	2,430	12%
30	**Non-network opex**	3,521	3,819	8%
31	**Operational expenditure**	8,661	10,030	16%
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	–	–	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	205	222	8%
42				

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

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

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2023
Network / Sub-Network Name	OtagoNet Joint Venture

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

sch ref	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)
15	1	Domestic	Standard	6,826	51,753
16	2	Commerical	Standard	3,330	52,540
17	4	Major Customers	Standard	109	85,039
18	5	Unmetered	Standard	82	146
19	6	Street lights	Standard	9	705
20	7 & 8	Low user	Standard	5,155	27,935
21	Non Standard	Commerical	Non-standard	3	198,530
22	LLNW	Domestic	Standard	3,355	22,207
23	LLNW	Non Domestic	Standard	479	13,016
24	LLNW	Half Hour	Standard	13	10,639
25	*Add extra rows for additional consumer groups or price category codes as necessary*				
26			Standard consumer totals	19,358	263,980
27			Non-standard consumer totals	3	198,530
28			Total for all consumers	19,361	462,510

Billed quantities by price component

sch ref	Consumer group name or price category code	Variable day energy sales	Variable Peak energy Sales	Variable Shoulder energy sales	Variable Night energy sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases	Variable energy sales			
13	Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kwh			
15	1					21,764	19,346	15,030				
16	2					21,990	19,505	15,319				
17	4	59,602										
18	5					61	54	43				
19	6					295	262	206				
20	7 & 8		10,779	9,523	7,633							
21	Non Standard	131,793										
22	LLNW								22,207			
23	LLNW											
24	LLNW											
26	Standard consumer totals	59,602	10,779	9,523	7,633	44,110	39,167	30,598	22,207	–	–	–
27	Non-standard consumer totals	131,793	–	–	–	–	–	–	–	–	–	–
28	Total for all consumers	191,395	10,779	9,523	7,633	44,110	39,167	30,598	22,207	–	–	–

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

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

sch ref	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)
37	1	Domestic	Standard	$8,245		$7,293	$952
38	2	Commerical	Standard	$7,921		$7,006	$915
39	4	Major Customers	Standard	$3,437		$1,373	$2,064
40	5	Unmetered	Standard	$30		$27	$3
41	6	Street lights	Standard	$116		$103	$13
42	7 & 8	Low user	Standard	$4,318		$3,819	$499
43	Non Standard	Major Customers	Non-standard	$3,314		$409	$2,904
	Generation	Generation	Standard	$343		$342	$1
44	LLNW	Domestic	Standard	$2,988		$2,528	$460
45	LLNW	Non Domestic	Standard	$1,229		$1,039	$189
46	LLNW	Half Hour	Standard	$732		$399	$334
47	*Add extra rows for additional consumer groups or price category codes as necessary*						
48			Standard consumer totals	$29,360	–	$23,929	$5,431
49			Non-standard consumer totals	$3,314	–	$409	$2,904
50			Total for all consumers	$32,674	–	$24,339	$8,335

Line charge revenues ($000) by price component

sch ref	Consumer group name or price category code	Fixed	Kva	Variable day energy sales	Variable Peak energy Sales	Variable Shoulder energy sales	Variable Night energy sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases	Fixed	Variable
35	Rate (eg, $ per day, $ per kWh, etc.)	$/Day	Per/kVa	kWh	kWh	kWh	kWh	kWh	kWh	kWh	$/kW	$/kWh
37	1	$3,523						$2,407	$1,973	$343		
38	2		$3,143					$2,440	$1,989	$349		
39	4	$2,575		$862								
40	5	$17						$7	$6	$1		
41	6	$52						$33	$27	$5		
42	7 & 8	$565			$1,897	$1,649	$208					
43	Non Standard	$3,314										
	Generation	$343										
44	LLNW	$365										$2,624
45	LLNW	$617									$612	
46	LLNW	$732										
48	Standard consumer totals	$8,789	$3,143	$862	$1,897	$1,649	$208	$4,886	$3,994	$698	$612	$2,624
49	Non-standard consumer totals	$3,314	–	–	–	–	–	–	–	–	–	–
50	Total for all consumers	$12,103	$3,143	$862	$1,897	$1,649	$208	$4,886	$3,994	$698	$612	$2,624

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

Check: OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end: 1

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**
Network / Sub-Network Name	**Otago Sub-Network**

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)
1	Domestic	Standard	6,826	51,753
2	Commerical	Standard	3,330	52,540
4	Major Customers	Standard	109	85,039
5	Unmetered	Standard	82	146
6	Street lights	Standard	9	705
7 & 8	Low user	Standard	5,155	27,935
Non Standard	Commerical	Non-standard	3	198,530
		[Select one]		
		[Select one]		
		[Select one]		
Add extra rows for additional consumer groups or price category codes as necessary				
		Standard consumer totals	15,511	218,119
		Non-standard consumer totals	3	198,530
		Total for all consumers	15,514	416,648

Billed quantities by price component

Consumer group name or price category code	Price component	Variable day energy sales	Variable Peak energy Sales	Variable Shoulder energy sales	Variable Night energy sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases		
	Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh	kWh	kWh	kWh		
1						21,764	19,346	15,030		
2						21,990	19,505	15,319		
4		59,602								
5						61	54	43		
6						295	262	206		
7 & 8			10,779	9,523	7,633					
Non Standard		131,793								
Standard consumer totals		59,602				44,110	39,167	30,598	–	–
Non-standard consumer totals		131,793				–	–	–	–	–
Total for all consumers		191,395				44,110	39,167	30,598	–	–

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)
1	Domestic	Standard	$8,245		$7,293	$952
2	Commerical	Standard	$7,921		$7,006	$915
4	Major Customers	Standard	$3,437		$1,373	$2,064
5	Unmetered	Standard	$30		$27	$3
6	Street lights	Standard	$116		$103	$13
7 & 8	Low user	Standard	$4,318		$3,819	$499
Non Standard	Major Customers	Non-standard	$3,314		$409	$2,904
Generation	Generation	Standard	$343		$342	$1
			–			
			–			
Add extra rows for additional consumer groups or price category codes as necessary						
		Standard consumer totals	$24,411	–	$19,963	$4,448
		Non-standard consumer totals	$3,314	–	$409	$2,904
		Total for all consumers	$27,725	–	$20,373	$7,352

Line charge revenues ($000) by price component

Consumer group name or price category code	Price component	Fixed	Kva	Variable day energy sales	Variable Peak energy Sales	Variable Shoulder energy sales	Variable Night energy sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases
	Rate (eg, $ per day, $ per kWh, etc.)	$/Day	Per/kVa	kWh	kWh	kWh	kWh	kWh	kWh	kWh
1		$3,523						$2,407	$1,973	$343
2			$3,143					$2,440	$1,989	$349
4		$2,575		$862						
5		$17						$7	$6	$1
6		$52						$33	$27	$5
7 & 8		$565			$1,897	$1,649	$208			
Non Standard		$3,314								
Generation		$343								
Standard consumer totals		$7,075	$3,143	$862	$1,897	$1,649	$208	$4,886	$3,994	$698
Non-standard consumer totals		$3,314	–	–	–	–	–	–	–	–
Total for all consumers		$10,389	$3,143	$862	$1,897	$1,649	$208	$4,886	$3,994	$698

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

Check: OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	1

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2023
Sub-Network Name	Lakeland Frankton Sub-Network

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	Billed quantities by price component					
				Price component	Variable energy sales					
				Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kwh					
LLNW	Domestic	Standard	3,355	22,207	22,207					
LLNW	Non Domestic	Standard	479	13,016						
LLNW	Half Hour	Standard	13	10,639						
Add extra rows for additional consumer groups or price category codes as necessary										
		Standard consumer totals	3,847	45,862	22,207	–	–	–	–	–
		Non-standard consumer totals	–	–	–	–	–	–	–	–
		Total for all consumers	3,847	45,862	22,207	–	–	–	–	–

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Line charge revenues ($000) by price component					
						Price component	Fixed	Fixed	Variable			
						Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kW	$/kWh			
LLNW	Domestic	Standard	$2,988		$2,528	$460	$365		$2,624			
LLNW	Non Domestic	Standard	$1,229		$1,039	$189	$617	$612				
LLNW	Half Hour	Standard	$732		$399	$334	$732					
			–									
			–									
			–									
			–									
			–									
			–									
			–									
Add extra rows for additional consumer groups or price category codes as necessary												
		Standard consumer totals	$4,949	–	$3,966	$983	$1,714	$612	$2,624	–	–	–
		Non-standard consumer totals	–	–	–	–	–	–	–	–	–	–
		Total for all consumers	$4,949	–	$3,966	$983	$1,714	$612	$2,624	–	–	–

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

Check OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end –

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2023
Network / Sub-network Name	OtagoNet Joint Venture

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.	35,449	35,684	235	3
10	All	Overhead Line	Wood poles	No.	14,963	14,778	(185)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	697	698	1	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	19	18	(0)	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	45	45	–	3
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.	7	7	–	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	214	214	–	2
29	HV	Zone substation switchgear	33kV RMU	No.	1	1	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	7	7	–	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	35	38	3	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	116	114	(2)	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	3	5	2	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	44	44	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,343	2,345	2	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	904	895	(10)	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	86	88	1	1
39	HV	Distribution Cable	Distribution UG PILC	km	4	3	(1)	1
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.	32	32	–	2
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5,132	5,171	39	1
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.	84	91	7	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,054	4,067	13	1
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	345	357	12	2
48	HV	Distribution Transformer	Voltage regulators	No.	42	41	(1)	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	16	15	(1)	3
50	LV	LV Line	LV OH Conductor	km	469	465	(4)	1
51	LV	LV Cable	LV UG Cable	km	102	110	8	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	107	118	11	1
53	LV	Connections	OH/UG consumer service connections	No.	19,326	19,638	312	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	251	258	7	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	2	2	–	3
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	5	5	–	3
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Otago Sub-Network**

SCHEDULE 9a: ASSET REGISTER

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

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	35,449	35,684	235	3
10	All	Overhead Line	Wood poles	No.	14,963	14,778	(185)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	697	698	1	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	13	13	0	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	44	44	–	3
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.	7	7	–	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	214	214	–	2
29	HV	Zone substation switchgear	33kV RMU	No.	1	1	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	7	7	–	3
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	35	38	3	3
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	106	104	(2)	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	3	5	2	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	42	42	–	3
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	2,343	2,345	2	2
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	904	895	(10)	2
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	37	37	0	1
39	HV	Distribution Cable	Distribution UG PILC	km	3	3	–	1
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.	32	32	–	2
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5,132	5,171	39	1
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.	10	10	–	2
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	4,054	4,067	13	1
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	257	264	7	2
48	HV	Distribution Transformer	Voltage regulators	No.	42	41	(1)	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	16	15	(1)	3
50	LV	LV Line	LV OH Conductor	km	469	465	(4)	1
51	LV	LV Cable	LV UG Cable	km	47	47	0	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	82	85	3	1
53	LV	Connections	OH/UG consumer service connections	No.	16,258	16,271	13	1
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	241	248	7	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	3
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	5	5	–	3
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Lakeland Frankton Sub-Network**

SCHEDULE 9a: ASSET REGISTER

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

sch ref	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.	–	–	–	N/A
10	All	Overhead Line	Wood poles	No.	–	–	–	N/A
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	N/A
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	6	6	0	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	1	1	–	3
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.	–	–	–	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	N/A
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	N/A
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	10	10	–	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	N/A
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	2	2	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	–	–	–	N/A
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	49	50	1	2
39	HV	Distribution Cable	Distribution UG PILC	km	1	1	0	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.	–	–	–	N/A
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	–	N/A
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.	74	82	8	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	–	N/A
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	88	93	5	2
48	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	N/A
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	N/A
50	LV	LV Line	LV OH Conductor	km	–	–	–	N/A
51	LV	LV Cable	LV UG Cable	km	55	61	6	2
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	25	32	7	4
53	LV	Connections	OH/UG consumer service connections	No.	3,068	3,367	299	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	10	10	–	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	3
56	All	Capacitor Banks	Capacitors including controls	No	–	–	–	N/A
57	All	Load Control	Centralised plant	Lot	–	–	–	N/A
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2023
Network / Sub-network Name	OtagoNet Joint Venture

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)

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)
9																																									
10	All	Overhead Line	Concrete poles / steel structure	No.	247	742	4,151	3,803	4,746	6,395	1,891	131	231	53	263	119	125	46	46	197	945	1,000	1,091	1,073	876	920	936	641	972	700	446	648	537	494	133	–	–	1,086	35,684		3
11	All	Overhead Line	Wood poles	No.	19	222	1,536	1,220	744	671	3,552	399	736	517	504	262	502	555	797	651	221	33	10	21	22	90	62	54	64	60	41	148	106	80	13	–	–	866	14,778		3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	13	63	157	116	86	67	0	4	3	18	1	–	1	2	–	2	2	–	48	1	–	13	2	–	–	0	1	–	–	–	–	–	96	698		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	–	0	–	–	–	0	1	–	–	1	–	6	–	–	–	1	–	1	0	–	–	0	8	1	–	–	–	–	0	18		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	2	10	7	5	7	–	–	–	–	–	–	–	1	2	2	–	1	–	1	–	–	2	–	–	–	–	–	–	–	–	–	5	45		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	6	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	14	24	23	49	30	–	1	1	11	2	5	2	3	7	–	3	2	7	–	2	3	2	1	3	6	8	2	–	–	–	–	3	214		3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	1		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	1	11	6	–	–	–	–	–	–	1	1	–	–	–	1	1	1	–	–	2	1	3	4	2	–	1	–	–	–	–	38		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	3	6	8	41	–	1	–	–	2	6	–	2	–	21	–	–	–	9	1	–	8	2	–	–	2	–	1	1	–	–	–	114		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	1	–	–	–	–	–	–	–	2	–	–	–	–	5		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	1	–	2	8	6	6	2	–	–	–	–	–	–	4	2	1	2	1	–	2	2	2	–	1	1	–	–	1	–	–	–	–	–	–	44		3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3	30	135	215	248	306	335	76	93	45	42	25	51	33	61	59	67	99	50	61	76	37	46	22	18	4	5	23	13	21	4	–	–	41	2,345		2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
38	HV	Distribution Line	SWER conductor	km	–	–	183	106	98	151	103	3	2	2	8	3	5	22	3	9	20	11	44	43	16	15	2	0	3	21	1	4	7	6	1	–	–	3	895		2
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	0	0	0	0	2	1	0	0	1	2	2	1	2	2	10	2	2	2	5	7	12	5	11	5	2	5	2	3	–	–	–	2	88		1
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	1	–	–	–	–	–	–	–	–	0	0	–	–	0	–	–	1	–	0	–	0	–	–	0	–	–	–	–	–	–	–	3		1
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	–	3	–	–	–	–	7	4	2	6	5	–	1	–	–	–	–	–	32		2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	23	647	672	750	514	486	25	92	88	70	63	92	104	114	110	104	112	83	83	53	73	100	64	67	90	64	85	118	127	25	–	–	73	5,171		1
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.	–	–	–	–	–	–	4	–	–	–	2	–	–	1	–	1	5	3	1	–	4	8	10	10	5	12	8	4	6	6	1	–	–	–	91		2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	23	640	532	538	399	444	25	76	73	53	51	77	81	97	98	76	80	59	55	36	52	80	46	49	63	44	49	76	76	19	–	–	–	4,067		1
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	1	29	7	21	4	9	5	4	3	14	11	15	13	18	9	6	14	11	16	20	21	15	13	18	19	20	20	1	–	–	–	357		2
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	1	4	–	–	–	1	2	2	–	–	1	2	2	–	2	1	2	11	3	2	2	1	2	–	–	–	–	–	–	41		3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	7	–	3	–	–	–	–	–	–	–	1	–	1	1	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	15		3
51	LV	LV Line	LV OH Conductor	km	1	4	146	35	41	10	7	0	1	3	2	1	3	3	4	2	1	2	2	2	2	2	3	1	1	2	2	3	5	4	0	–	–	168	465		1
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	4	3	0	0	0	0	1	2	2	1	6	2	1	1	2	1	3	8	7	11	10	10	6	8	2	7	0	–	–	8	110		1
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	0	1	1	–	–	–	–	–	–	–	0	0	0	–	0	0	–	1	1	5	3	4	4	2	7	4	7	–	–	–	76	118		1
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	10,880	907	106	101	481	543	514	509	438	216	139	102	106	91	113	191	333	379	422	582	508	684	455	663	101	–	–	74	19,638		1
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	7	33	35	–	4	–	–	6	4	4	4	15	11	13	3	4	13	1	11	18	7	13	22	8	5	5	1	–	–	11	258		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	Lot	–	–	–	–	–	–	–	1	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2		3
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	–	1	–	1	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	1	–	–	–	–	–	–	5		3
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A

Company Name: OtagoNet Joint Venture
For Year Ended: 31 March 2023
Network / Sub-network Name: Otago Sub-Network

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)**

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.	247	742	4,151	3,803	4,746	6,395	1,891	131	231	53	263	119	125	46	46	197	945	1,000	1,091	1,073	876	920	936	641	972	700	446	648	537	494	133	–	–	1,086	35,684		3
11	All	Overhead Line	Wood poles	No.	19	222	1,536	1,220	744	671	3,552	399	736	517	504	262	502	555	797	651	221	33	10	21	22	90	62	54	64	60	41	148	106	80	13	–	–	866	14,778		3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	13	63	157	116	86	67	0	4	3	18	1	–	1	2	–	2	2	–	48	1	–	13	2	–	–	0	1	–	–	–	–	–	96	698		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	0	–	0	–	–	–	0	1	–	–	1	–	0	–	–	–	1	–	1	0	–	–	0	8	1	–	–	–	–	0	13		3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	2	10	7	5	7	–	–	–	–	–	–	–	1	2	1	–	1	–	1	–	–	2	–	–	–	–	–	–	–	–	–	5	44		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	6	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	14	24	23	49	30	–	1	1	11	2	5	2	3	7	–	3	2	7	–	2	3	2	1	3	6	8	2	–	–	–	–	3	214		3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	1		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	1	11	6	–	–	–	–	–	–	1	1	–	–	–	1	1	1	–	–	2	1	3	4	2	–	1	–	–	–	–	38		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	3	6	8	41	–	1	–	–	2	6	–	2	–	11	–	–	–	9	1	–	8	2	–	–	2	–	1	1	–	–	–	104		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	1	–	–	–	–	–	–	2	–	–	–	–	–	5		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	1	–	2	8	6	6	2	–	–	–	–	–	–	4	2	1	–	1	–	2	2	2	–	1	1	–	–	1	–	–	–	–	–	–	42		3
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3	30	135	215	248	306	335	76	93	45	42	25	51	33	61	59	67	99	50	61	76	37	46	22	18	4	5	23	13	21	4	–	–	41	2,345		2
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
38	HV	Distribution Line	SWER conductor	km	–	–	183	106	98	151	103	3	2	2	8	3	5	22	3	9	20	11	44	43	16	15	2	0	3	21	1	4	7	6	1	–	–	3	895		2
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	0	0	0	0	2	1	0	0	1	2	1	1	2	2	1	1	2	2	1	3	6	1	3	0	0	3	1	0	–	–	–	1	37		1
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	1	–	–	–	–	–	–	–	–	0	0	–	–	0	–	–	1	–	0	–	0	–	–	0	–	–	–	–	–	–	–	3		1
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	–	3	–	–	–	–	7	4	2	6	5	–	1	–	–	–	–	–	32		2
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	23	647	672	750	514	486	25	92	88	70	63	92	104	114	110	104	112	83	83	53	73	100	64	67	90	64	85	118	127	25	–	–	73	5,171		1
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.	–	–	–	–	–	–	4	–	–	–	2	–	–	–	–	1	–	1	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	10		2
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	23	640	532	538	399	444	25	76	73	53	51	77	81	97	98	76	80	59	55	36	52	80	46	49	63	44	49	76	76	19	–	–	–	4,067		1
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	1	29	7	21	4	9	5	4	3	13	11	14	12	11	7	6	14	8	10	9	14	6	5	10	12	9	9	1	–	–	–	264		2
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	1	4	–	–	–	1	2	2	–	–	1	2	2	–	2	1	2	11	3	2	2	1	2	–	–	–	–	–	–	41		3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	7	–	3	–	–	–	–	–	–	–	1	–	1	1	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	15		3
51	LV	LV Line	LV OH Conductor	km	1	4	146	35	41	10	7	0	1	3	2	1	3	3	4	2	1	2	2	2	2	2	3	1	1	2	2	3	5	4	0	–	–	168	465		1
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	4	3	0	0	0	0	1	1	2	1	6	2	1	1	2	1	2	1	2	2	3	2	1	2	1	1	0	–	–	4	47		1
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	0	1	1	–	–	–	–	–	–	–	0	0	0	–	0	0	–	–	–	1	0	1	1	0	1	2	3	–	–	–	73	85		1
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	10,880	907	106	101	469	532	486	476	396	196	134	88	100	86	73	96	125	84	103	122	147	156	194	167	25	–	–	22	16,271		1
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	7	33	35	–	4	–	–	6	4	4	4	15	4	13	3	1	13	1	11	18	7	13	22	8	5	5	1	–	–	11	248		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	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	1	–	–	–	–	–	–	5		3
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Lakeland Frankton Sub-Network**

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)**

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)
9																																									
10	All	Overhead Line	Concrete poles / steel structure	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
11	All	Overhead Line	Wood poles	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	–	6		4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
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	–	–	–	–	–	–	–	–	–	–	–	–	1	0	0	–	9	1	0	–	4	4	6	4	8	5	2	2	1	3	–	–	–	1	50		2
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	–	–	–	–	–	–	–	–	0	0	–	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		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.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
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.	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	5	2	1	–	4	8	10	10	5	12	8	4	5	6	1	–	–	–	82		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	–	–	–	–	–	–	–	–	–	1	–	1	1	7	2	–	–	3	6	11	7	9	8	8	7	11	11	–	–	–	–	93		2
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
51	LV	LV Line	LV OH Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
52	LV	LV Cable	LV UG Cable	km	–	–	–	–	–	–	–	–	–	–	–	1	0	0	0	0	0	0	–	–	1	7	5	9	7	8	5	6	1	6	–	–	–	4	62		2
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	1	1	4	3	3	3	2	6	2	4	–	–	–	3	32		4
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	–	–	–	–	–	–	12	11	28	33	42	20	5	14	6	5	40	95	208	295	319	460	361	528	261	496	76	–	–	52	3,367		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	–	3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10		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	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2023
Network / Sub-network Name	OtagoNet Joint Venture

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref				
9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	74	–	74
13	33kV	623	19	642
14	SWER (all SWER voltages)	889	6	895
15	22kV (other than SWER)	0	47	47
16	6.6kV to 11kV (inclusive—other than SWER)	2,345	43	2,388
17	Low voltage (< 1kV)	465	108	573
18	**Total circuit length (for supply)**	4,396	223	4,619
19				
20	Dedicated street lighting circuit length (km)	81	37	118
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	328	7%	
25	Rural	903	21%	
26	Remote only	593	13%	
27	Rugged only	1,798	41%	
28	Remote and rugged	672	15%	
29	Unallocated overhead lines	102	2%	
30	**Total overhead length**	4,396	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,121	24%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	663	15%	

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Otago Sub-Network**

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref		Overhead (km)	Underground (km)	Total circuit length (km)
9				
10	**Circuit length by operating voltage (at year end)**			
11	> 66kV	–	–	–
12	50kV & 66kV	74	–	74
13	33kV	623	13	636
14	SWER (all SWER voltages)	889	6	895
15	22kV (other than SWER)	0	0	0
16	6.6kV to 11kV (inclusive—other than SWER)	2,345	41	2,386
17	Low voltage (< 1kV)	465	47	512
18	**Total circuit length (for supply)**	4,396	106	4,503
19				
20	Dedicated street lighting circuit length (km)	81	5	85
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
22				

sch ref		Circuit length (km)	(% of total overhead length)
23	**Overhead circuit length by terrain (at year end)**		
24	Urban	328	7%
25	Rural	903	21%
26	Remote only	593	13%
27	Rugged only	1,798	41%
28	Remote and rugged	672	15%
29	Unallocated overhead lines	102	2%
30	**Total overhead length**	4,396	100%
31			

sch ref		Circuit length (km)	(% of total circuit length)
32			
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,121	25%

sch ref		Circuit length (km)	(% of total overhead length)
34			
35	Overhead circuit requiring vegetation management	663	15%

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2023
Network / Sub-network Name	Lakeland Frankton Sub-Network

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

		Overhead (km)	Underground (km)	Total circuit length (km)
9				
10	**Circuit length by operating voltage (at year end)**			
11	> 66kV	–	–	–
12	50kV & 66kV	–	–	–
13	33kV	–	6	6
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	–	47	47
16	6.6kV to 11kV (inclusive—other than SWER)	–	2	2
17	Low voltage (< 1kV)	0	61	61
18	**Total circuit length (for supply)**	0	116	116
19				
20	Dedicated street lighting circuit length (km)	–	32	32
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			
22				

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

		Circuit length (km)	(% of total circuit length)
32			
33	Length of circuit within 10km of coastline or geothermal areas (where known)	–	–

		Circuit length (km)	(% of total overhead length)
34			
35	Overhead circuit requiring vegetation management	–	–

Company Name: OtagoNet Joint Venture
For Year Ended: 31 March 2023

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref	Location *	Average number of ICPs in disclosure year	Line charge revenue ($000)
8			
9	Lakeland Wanaka GXP NLK0111 [used Average ICP Count as per Schedule 8(i)]	562	475
10	Lakeland Clearview GXP CLV0111 [used Average ICP Count as per Schedule 8(i)]	42	16
11	Lakeland Wooing Tree GXP WRT0111 [used Average ICP Count as per Schedule 8(i)]	26	12
12	Lakeland NgaiTahu GXP NTU0111 [used Average ICP Count as per Schedule 8(i)]	16	4
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	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**OtagoNet Joint Venture**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref			
8	**9e(i): Consumer Connections and Decommissionings**		
9	*Number of ICPs connected during year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Domestic	766	
12	Non Domestic	81	
13	Half Hour Individual	1	
14			
15			
16	** include additional rows if needed*		
17	**Connections total**	848	
18			
19	*Number of ICPs decommissioned during year by consumer type*		
20	*Consumer types defined by EDB**	**Number of decommissionings**	
21	Low User	1	
22	Domestic	28	
23	Non Domestic	24	
24	Unmetered	2	
25			
26	** include additional rows if needed*		
27	**Decommissionings total**	55	
28			
29	**Distributed generation**		
30	Number of connections made in year	69	**connections**
32	Capacity of distributed generation installed in year	0.42	**MVA**
33			
34	**9e(ii): System Demand**		
35			
36		**Demand at time of maximum coincident demand (MW)**	
37	**Maximum coincident system demand**		
38	GXP demand	68	
39	*plus* Distributed generation output at HV and above	4	
40	**Maximum coincident system demand**	72	
41	*less* Net transfers to (from) other EDBs at HV and above	(1)	
42	**Demand on system for supply to consumers' connection points**	73	
43	**Electricity volumes carried**	**Energy (GWh)**	
44	Electricity supplied from GXPs	419	
45	*less* Electricity exports to GXPs	–	
46	*plus* Electricity supplied from distributed generation	59	
47	*less* Net electricity supplied to (from) other EDBs	(4)	
48	**Electricity entering system for supply to consumers' connection points**	482	
49	*less* Total energy delivered to ICPs	463	
51	**Electricity losses (loss ratio)**	19	3.9%
52			
53	**Load factor**	0.75	
54	**9e(iii): Transformer Capacity**		
55		**(MVA)**	
56	Distribution transformer capacity (EDB owned)	236	
57	Distribution transformer capacity (Non-EDB owned, estimated)	9	
58	**Total distribution transformer capacity**	245	
59			
60	**Zone substation transformer capacity**	162	
61			

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Otago Sub-Network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref

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

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

sch ref	Consumer types defined by EDB*	Number of connections (ICPs)
11	Domestic	127
12	Non Domestic	29
13		
14		
15		
16	* include additional rows if needed	
17	**Connections total**	156

18

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

sch ref	Consumer types defined by EDB*	Number of decommissionings
21	Low User	1
22	Domestic	23
23	Non Domestic	14
24	Unmetered	2
25		
26	* include additional rows if needed	
27	**Decommissionings total**	40

28

29 **Distributed generation**

sch ref			
30	Number of connections made in year		connections
32	Capacity of distributed generation installed in year		MVA

33

34 ### 9e(ii): System Demand

35

sch ref			Demand at time of maximum coincident demand (MW)
37		**Maximum coincident system demand**	
38		GXP demand	59
39	*plus*	Distributed generation output at HV and above	4
40		**Maximum coincident system demand**	64
41	*less*	Net transfers to (from) other EDBs at HV and above	
42		**Demand on system for supply to consumers' connection points**	64

sch ref			Energy (GWh)	
43		**Electricity volumes carried**		
44		Electricity supplied from GXPs	376	
45	*less*	Electricity exports to GXPs	–	
46	*plus*	Electricity supplied from distributed generation	59	
47	*less*	Net electricity supplied to (from) other EDBs	–	
48		**Electricity entering system for supply to consumers' connection points**	435	
49	*less*	Total energy delivered to ICPs	417	
51		**Electricity losses (loss ratio)**	18	4.1%
52				
53		**Load factor**	0.78	

54 ### 9e(iii): Transformer Capacity

sch ref		(MVA)
56	Distribution transformer capacity (EDB owned)	197
57	Distribution transformer capacity (Non-EDB owned, estimated)	9
58	**Total distribution transformer capacity**	206
59		
60	**Zone substation transformer capacity**	137
61		

Company Name	**OtagoNet Joint Venture**
For Year Ended	**31 March 2023**
Network / Sub-network Name	**Lakeland Frankton Sub-Network**

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
8	**9e(i): Consumer Connections and Decommissionings**			
9	*Number of ICPs connected during year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Domestic		639	
12	Non Domestic		52	
13	Half Hour Individual		1	
14				
15				
16	** include additional rows if needed*			
17	**Connections total**		692	
18				
19	*Number of ICPs decommissioned during year by consumer type*			
20	*Consumer types defined by EDB**		**Number of decommissionings**	
21	Domestic		5	
22	Non Domestic		10	
23				
24				
25				
26	** include additional rows if needed*			
27	**Decommissionings total**		15	
28				
29	**Distributed generation**			
30	Number of connections made in year			**connections**
32	Capacity of distributed generation installed in year			**MVA**
33				
34	**9e(ii): System Demand**			
35				
36				
37	**Maximum coincident system demand**		**Demand at time of maximum coincident demand (MW)**	
38		GXP demand	8	
39	*plus*	Distributed generation output at HV and above	–	
40	**Maximum coincident system demand**		8	
41	*less*	Net transfers to (from) other EDBs at HV and above	(1)	
42	**Demand on system for supply to consumers' connection points**		9	
43	**Electricity volumes carried**		**Energy (GWh)**	
44		Electricity supplied from GXPs	43	
45	*less*	Electricity exports to GXPs	–	
46	*plus*	Electricity supplied from distributed generation	0.3	
47	*less*	Net electricity supplied to (from) other EDBs	(4)	
48	**Electricity entering system for supply to consumers' connection points**		47	
49	*less*	Total energy delivered to ICPs	–	
51	**Electricity losses (loss ratio)**		47	100.0%
52				
53	**Load factor**		0.60	
54	**9e(iii): Transformer Capacity**			
55			**(MVA)**	
56		Distribution transformer capacity (EDB owned)	39	
57		Distribution transformer capacity (Non-EDB owned, estimated)	–	
58	**Total distribution transformer capacity**		39	
59				
60	**Zone substation transformer capacity**		25	
61				

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2023
Network / Sub-network Name	OtagoNet Joint Venture

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(i): Interruptions

Interruptions by class	Number of interruptions
Class A (planned interruptions by Transpower)	–
Class B (planned interruptions on the network)	370
Class C (unplanned interruptions on the network)	592
Class D (unplanned interruptions by Transpower)	1
Class E (unplanned interruptions of EDB owned generation)	–
Class F (unplanned interruptions of generation owned by others)	–
Class G (unplanned interruptions caused by another disclosing entity)	6
Class H (planned interruptions caused by another disclosing entity)	–
Class I (interruptions caused by parties not included above)	–
Total	969

Interruption restoration	≤3Hrs	>3hrs
Class C interruptions restored within	429	163

SAIFI and SAIDI by class	SAIFI	SAIDI
Class A (planned interruptions by Transpower)	–	–
Class B (planned interruptions on the network)	0.8631	251.42
Class C (unplanned interruptions on the network)	2.1229	256.20
Class D (unplanned interruptions by Transpower)	0.0838	3.20
Class E (unplanned interruptions of EDB owned generation)	–	–
Class F (unplanned interruptions of generation owned by others)	–	–
Class G (unplanned interruptions caused by another disclosing entity)	0.1468	9.13
Class H (planned interruptions caused by another disclosing entity)	–	–
Class I (interruptions caused by parties not included above)	–	–
Total	3.2166	519.95

Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
Classes B & C (interruptions on the network)	2.8920	455.33

Transitional SAIDI and SAIDI (previous method) — SAIFI — SAIDI

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

	SAIFI	SAIDI
Class B (planned interruptions on the network)	N/A	N/A
Class C (unplanned interruptions on the network)	N/A	N/A

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

Cause	SAIFI	SAIDI
Lightning	0.0590	7.43
Vegetation	0.4921	88.39
Adverse weather	0.2324	54.25
Adverse environment	0.0043	1.85
Third party interference	0.1055	9.82
Wildlife	0.0752	8.94
Human error	0.0034	0.99
Defective equipment	0.5337	58.90
Cause unknown	0.6173	25.63

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

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.0777	27.72
Subtransmission cables	–	–
Subtransmission other	0.0612	20.74
Distribution lines (excluding LV)	0.6259	183.13
Distribution cables (excluding LV)	0.0001	0.02
Distribution other (excluding LV)	0.0982	19.81

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.7604	116.67
Subtransmission cables	–	–
Subtransmission other	0.1359	3.22
Distribution lines (excluding LV)	1.0516	119.16
Distribution cables (excluding LV)	0.0083	0.80
Distribution other (excluding LV)	0.1667	16.35

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	25	697.5	3.58
Subtransmission cables	–	18.7	–
Subtransmission other	3		
Distribution lines (excluding LV)	407	3,234.0	12.59
Distribution cables (excluding LV)	5	96.0	5.21
Distribution other (excluding LV)	152		
Total	592		

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2023
Network / Sub-network Name	Otago Sub-Network

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 **10(i): Interruptions**

sch ref	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	359
12	Class C (unplanned interruptions on the network)	580
13	Class D (unplanned interruptions by Transpower)	1
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)	–
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	**Total**	940

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	422	158

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	1.0508	308.24
27	Class C (unplanned interruptions on the network)	2.5412	302.87
28	Class D (unplanned interruptions by Transpower)	0.1043	3.96
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)	–	–
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	**Total**	3.6963	615.07

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	N/A	N/A

39 **Transitional SAIDI and SAIDI (previous method)** — SAIFI / SAIDI

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

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

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

sch ref	Cause	SAIFI	SAIDI
47	Lightning	0.0735	9.25
48	Vegetation	0.6121	109.94
49	Adverse weather	0.2892	67.50
50	Adverse environment	0.0054	2.30
51	Third party interference	0.1295	11.48
52	Wildlife	0.0935	11.13
53	Human error	0.0043	1.24
54	Defective equipment	0.5740	58.73
55	Cause unknown	0.7597	31.30

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

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

sch ref	Main equipment involved	SAIFI	SAIDI
67	Subtransmission lines	0.0966	34.49
68	Subtransmission cables	–	–
69	Subtransmission other	0.0761	25.80
70	Distribution lines (excluding LV)	0.7774	227.20
71	Distribution cables (excluding LV)	–	–
72	Distribution other (excluding LV)	0.1007	20.75

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

sch ref	Main equipment involved	SAIFI	SAIDI
76	Subtransmission lines	0.9461	145.16
77	Subtransmission cables	–	–
78	Subtransmission other	0.1691	4.01
79	Distribution lines (excluding LV)	1.2930	144.60
80	Distribution cables (excluding LV)	0.0021	0.41
81	Distribution other (excluding LV)	0.1309	8.69

82 **10(v): Fault Rate**

sch ref	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
84	Subtransmission lines	25	697.5	3.58
85	Subtransmission cables	–	12.6	–
86	Subtransmission other	3		
87	Distribution lines (excluding LV)	404	3,233.9	12.49
88	Distribution cables (excluding LV)	4	46.3	8.64
89	Distribution other (excluding LV)	144		
90	**Total**	580		

Company Name	OtagoNet Joint Venture
For Year Ended	31 March 2023
Network / Sub-network Name	Lakeland Frankton Sub-Network

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 10(i): Interruptions

sch ref		Number of interruptions
9	**Interruptions by class**	
10	Class A (planned interruptions by Transpower)	–
11	Class B (planned interruptions on the network)	6
12	Class C (unplanned interruptions on the network)	5
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)	1
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	–
19	Total	12
20		

sch ref		≤3Hrs	>3hrs
21	**Interruption restoration**		
22	Class C interruptions restored within	4	1
23			

sch ref		SAIFI	SAIDI
24	**SAIFI and SAIDI by class**		
25	Class A (planned interruptions by Transpower)	–	–
26	Class B (planned interruptions on the network)	0.0707	10.77
27	Class C (unplanned interruptions on the network)	0.1783	26.44
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)	0.0003	0.01
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	–	–
34	Total	0.2493	37.22
35			

sch ref		Normalised SAIFI	Normalised SAIDI
36	**Normalised SAIFI and SAIDI**		
37	Classes B & C (interruptions on the network)	N/A	N/A
38			

sch ref		SAIFI	SAIDI
39	**Transitional SAIDI and SAIDI (previous method)**		
40	*Where EDBs do not currently record their SAIFI and SAIDI values using the 'multi-count' approach, they shall continue to record their SAIFI and SAIDI values on the same basis that they employed as at 31 March 2023 as 'Transitional SAIFI' and 'Transitional SAIDI' values, in addition to their SAIFI and SAIDI values (Classes B & C) using the 'multi-count approach'.* ***This is a transitional reporting requirement that shall be in place for the 2024, 2025, and 2026 disclosure years.***		
41	Class B (planned interruptions on the network)	N/A	N/A
42	Class C (unplanned interruptions on the network)	N/A	N/A
43			

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

sch ref		SAIFI	SAIDI
45			
46	**Cause**		
47	Lightning	–	–
48	Vegetation	–	–
49	Adverse weather	–	–
50	Adverse environment	–	–
51	Third party interference	–	–
52	Wildlife	–	–
53	Human error	–	–
54	Defective equipment	0.1377	23.56
55	Cause unknown	0.0406	2.88
56			
57	**Breakdown of third party interference**		
58	Dig-in	N/A	N/A
59	Overhead contact	N/A	N/A
60	Vandalism	N/A	N/A
61	Vehicle damage	N/A	N/A
62	Other	N/A	N/A
63			

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

sch ref		SAIFI	SAIDI
65			
66	**Main equipment involved**		
67	Subtransmission lines	–	–
68	Subtransmission cables	–	–
69	Subtransmission other	–	–
70	Distribution lines (excluding LV)	–	–
71	Distribution cables (excluding LV)	0.0003	0.15
72	Distribution other (excluding LV)	0.0704	10.62

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

sch ref		SAIFI	SAIDI
74			
75	**Main equipment involved**		
76	Subtransmission lines	–	–
77	Subtransmission cables	–	–
78	Subtransmission other	–	–
79	Distribution lines (excluding LV)	–	–
80	Distribution cables (excluding LV)	0.0406	2.88
81	Distribution other (excluding LV)	0.1377	23.56

82 10(v): Fault Rate

sch ref		Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
83	**Main equipment involved**			
84	Subtransmission lines	–	–	–
85	Subtransmission cables	–	6	–
86	Subtransmission other	–		
87	Distribution lines (excluding LV)	–	–	–
88	Distribution cables (excluding LV)	1	49	2.04
89	Distribution other (excluding LV)	4		
90	Total	5		

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
OtagoNet achieved a post-tax ROI of 8.16% which is above the 75th percentile estimate of post-tax WACC of 5.56% and 8.67% vanilla ROI which is above the 75th percentile estimate of vanilla WACC of 6.07%. No items were reclassified.

Regulatory Profit (Schedule 3)

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

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

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

Box 2: Explanatory comment on regulatory profit
No items were reclassified in the disclosure year.

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

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

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

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

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

Value of the Regulatory Asset Base (Schedule 4)

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

Box 4: Explanatory comment on the value of the regulatory asset based (rolled forward)
The calculation of the Regulatory Asset Base (RAB) was stated using the 31 March 2022 closing figure of $240,495k as a starting point with inflationary indexing over the year to 31 March 2023 plus additions less disposals resulting to a $263,617k RAB closing balance. 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 $48k 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: Temporary differences / Tax effect of other temporary differences (current disclosure year)

Taxable Capital Contributions:	$ 1,130
	$ 1,130
Tax Rate:	28%
Temporary Differences	$ 316

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

OtagoNet Joint Venture costs directly attributable as all costs were 100% electricity distribution business.

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 operating 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 OtagoNet transformers and lines that are 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 incurred during the year and none disclosed within Schedule 6b.

Variance between forecast and actual expenditure (Schedule 7)

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

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

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

Capital Expenditure on Assets:

The actual expenditure on network assets was 27% above budget. Cost increases in materials resulting from supply shortages, commodity price increases, increased shipping costs and general inflationary pressures have led to increased capital expenditure costs.

Consumer connection:

- 48% overspent due to high levels of customer driven demand for subdivision reticulation, and more small new customer connections than allowed for.

System Growth:

- 18% overspent due to more than expected new medium voltage cabling works for load growth.

Asset replacement and renewal:

- 21% overspent mainly due to higher spending on line renewal than planned, including subtransmission, distribution and LV lines. Additional spending on ABS, distribution transformer and circuit breaker replacements also contributed to the overspend. Meanwhile there was lower expenditure in other areas due to delays on a substation project, and less Remote Area Power Supply project work than planned.

Asset Relocations:

- 1026% overspent by a significant margin due to unforeseen works relocating and undergrounding power lines for third parties.

Quality of supply:

- 33% underspent due to delayed construction of mobile substation site.

Other Reliability, Safety and Environment:

- 28% underspent, mainly attributed to a lower spend than planned on distribution earths' refurbishment.

Operational Expenditure:

Network opex was 21% above budget. Overall opex was 16% above budget. Cost increases in materials resulting from supply shortages, commodity price increases, increased shipping costs and general inflationary pressures have led to increased capital expenditure costs.

Service interruptions and emergencies:
- 5% overspent due to a larger amount of technical fault work than allowed for.

Vegetation management:
- 7% underspend due to initiating a new contractor.

Routine and corrective maintenance and inspection:
- 56% overspent due to higher spend than planned on corrective and routine maintenance, distribution routine inspections and subtransmission line minor maintenance.

Asset replacement and renewal:
- 9% overspent, attributed to a higher spends than planned on distribution transformer refurbishment and locks and security renewals.

Non-network opex:
- Expenditure within 8% of the budget.

Information relating to revenue and quantities for the disclosure year

15. In the box below provide-

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

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

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

Target revenue for the year was $32,428 million. The total billed revenue for the year was $32,674 million, which is $246k (1%) above.

The increase in revenue is attributable to the higher chargeable volumes than forecast in Otago region (Mass Market consumption exceeding budget) slightly offset by lower revenue in Lakeland region. The Lakeland Network Limited network continued to grow with an increase in Active Residential ICPs, however not all these ICPs were livened or consuming electricity for the whole year.

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

OtagoNet Joint Venture (OJV) has calculated and disclosed SAIDI and SAIFI consistent with the 2012 Electricity Distribution Business (EDB) ID Determination, with all amendments to 6 July 2023. Note that OJV has counted the successive interruptions within the initial interruption when calculating SAIFI in line with prior year.

OJV has disclosed a normalised SAIDI at 455.33 and normalised SAIFI at 2.8920 for 2022/23. Normalised SAIFI is 8% lower than the 2021/22 year, with normalise SAIDI 9% higher. OJV published ID Determination values for normalised SAIDI of 419.3 and normalised SAIFI of 3.16 for the 2021/22 year – meaning less interruptions.

The total number of power interruptions on OJV has decrease slightly from 2022/23 compared with 2021/22.

Class C SAIFI of 2.1229 was the major contributor to overall SAIFI, with a decrease of 11% to 2021/22. Class C SAIDI was 20% higher and Class B SAIDI was 14% higher than 2021/22, indicating longer times to restore supply.

The most significant cause of Class C interruptions was Vegetation, which greatly increased in frequency and duration compared with last year. Defective equipment, Adverse weather, and Cause unknown were also high contributors to Class C SAIDI.

80% of OJV's network is distribution lines, with 80% of planned interruptions and 69% of unplanned interruptions occurred on these lines. Subtransmission lines contributed over 4% of the unplanned interruptions (based on SAIDI).

Fault rates per 100km improved for lines with distribution lines improving to 12.59 faults per 100km and subtransmission lines to 3.58. Distribution cables declined to 4.90 with five faults compared to two faults last year.

The results were reflective of interruptions occurring predominantly on the Otago sub-network. Lakeland sub-network experienced five Class C interruptions this year, mostly caused by defective distribution equipment

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
OtagoNet insures its substations and network equipment. • Substations and network equipment are insured for $81.2 million. Lines and cables are not insured. OtagoNet 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

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

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

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

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

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

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

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

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

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

Nominal Prices are based on publicly available New Zealand Treasury's economic forecast indicated in the Half Year Economic and Fiscal Update (HYEFU) report released in December 2021:

	2022/23	2023/24	2024/25	2025/26	2026/27
Inflator (CAPEX & OPEX)	5.1%	3.1%	2.7%	2.4%	2.2%

In addition to the general inflation, material costs have increased by weighted average of 17% was included in the CAPEX forecasts for 2022 onwards.
Forecasts are in line with the business plan projections and explanations outlined in the Asset Management Plan.

SCHEDULE 15 VOLUNTARY EXPLANATORY NOTES

5. This Schedule enable EDBs to provide, should they wish to-

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

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

6. 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.

7. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

Schedule 5f – 5g (Cost and Asset Allocation Support)
No disclosure made on these schedules with no shared assets and minimal shared costs relating to rental properties.

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

There is currently no independent evidence to support the accuracy of installation control points ('ICP's') affected by an interruption, impacting the completeness and accuracy of ICP data included in the SAIDI and SAIFI outage statistics.

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

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

4. APPENDICES

APPENDIX A:

Related Party Transactions:

Additional Information Disclosures

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 2023), issued 6 July 2023, the following information is provided in support of:

- **OtagoNet Joint Venture's 2023 Information Disclosure**, for the year ended 31 March 2023 - Schedule 5(b) Related party Transactions

2. INFORMATION DISCLOSURE REQUIREMENTS

The information disclosed in this Information Disclosure package issued by OtagoNet Joint Venture (OJV) has been prepared in accordance with the Determination noted above.

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.

3. RELATED PARTY RELATIONSHIPS

In accordance with Input Methodology rules, a Related Party Transaction occurs when a regulated supplier transacts with an entity which is related to it by common shareholding or other common control.

The OJV Regulated Network is comprised of OtagoNet Joint Venture (OJV) and Lakeland Network Limited (LNL), formerly Electricity Southland Limited (ESL). The OJV Regulated Network and the network management company PowerNet Limited (PowerNet), are all 100% wholly owned by Electricity Invercargill Limited (EIL) and The Power Company Limited (TPCL), through their respective wholly owned subsidiary companies Pylon Limited and Last Tango Limited.

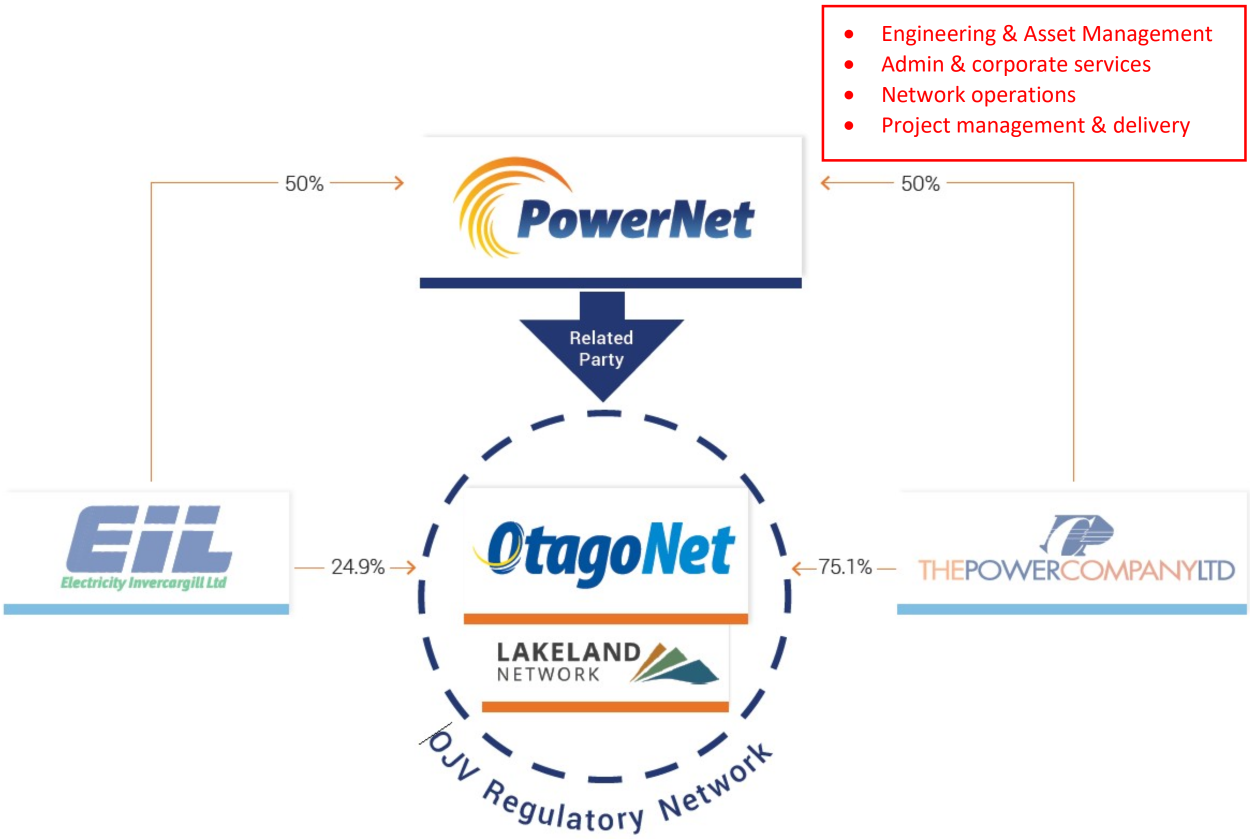
During the year ending 31 March 2023, OJV Regulated Network had related party transactions with the following entities:

- Goods and services provided by – PowerNet Limited and The Power Company Limited;

Ownership Structure

The parties to the OtagoNet Joint Venture consist of EIL and TPCL. PowerNet is a related party, due to its ownership by EIL and TPCL. The regulated OJV network also includes the LNL network, which has the same ownership as OJV. The following diagram illustrates the OJV Regulated Network's transactions with PowerNet, and the nature of related party transaction work undertaken.

ID Determination reference: 2.3.8



a. **PowerNet Limited**

EIL and TPCL jointly hold a 100% interest in electricity network management company PowerNet Limited and the regulated OJV network (OJV and LNL). PowerNet provides a range of field contracting, asset management, system control and finance and commercial services to the regulated OJV network. The value of the related party transactions for the year ended 31 March 2023 is categorised as follows:

		($000)
Operating Expenditure:		
i.	Service interruptions and emergencies	2,292
ii.	Vegetation management	906
iii.	Routine and corrective maintenance and inspection	2,833
iv.	Asset replacement and renewal (opex)	180
v.	System operations and network support	794
vi.	Business support	1,882
Capital Expenditure:		
vii.	Consumer connection	7,426
viii.	System growth	1,020
ix.	Asset replacement and renewal (capex)	10,405
x.	Asset relocations	383
xi.	Quality of supply	195
xii.	Other reliability, safety and environment	722
	Total Related Party expenditure from PowerNet	**29,038**

In the year to 31 March 2023, PowerNet provided 100% of the OJV and LNL Lines Business Capital Expenditure, and 89% 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 OJV and LNL, in the form of “agency agreements”.

Services provided under the agreement include:

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

b. **The Power Company Limited**

TPCL holds a 75.1% ownership of OtagoNet JV and LNL. The value of the related party transaction with TPCL during the year ended 31 March 2023, relates to the use of specialised equipment, categorised as follows:

		($’000)
Operating Expenditure:		
i.	System operations and network support	60
	Total Related Party expenditure from TPCL	**60**

Network Management Agreement ('Agency Agreement')

OJV (including LNL) incurs 100% of its capital expenditure and the majority of operating costs from PowerNet, for operating its electricity distribution businesses. PowerNet operates in accordance with the explicit terms and conditions of a Network Management Agreement (NMA).

While OJV & LNL own the Network distribution assets and provide electricity distribution services through their respective electricity networks in the Clutha and Central Otago region, under the NMA agreement PowerNet manages the maintenance, replacement or development activity associated with network assets, in accordance with an approved annual Capital and Maintenance Works programme. PowerNet has the exclusive right to provide Line Function Services, and also provide the business administration services on behalf of OJV and LNL.

PowerNet was established in 1994 to extract operational efficiencies from the merger of field work management, asset management and office based functions performed by TPCL and EIL. In 1993, there were two autonomous Lines Companies in Southland (TPCL and EIL). 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 2018 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 network and metering businesses it manages under the NMA's. These charges recover costs incurred in the performance of the system control services, asset management, corporate, finance and commercial services.

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

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

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

4. PROCUREMENT POLICY

ID Determination 2.3.10 & 2.3.11

Under the Network Management Agreement (NMA), OJV and LNL have contracted PowerNet to manage the operational functions, maintain the network assets, implement the Asset Management Plan, and provide business management services, and hence, act on behalf of OJV and LNL when project managing and purchasing required goods and services in the course of carrying out the responsibilities of the Agreement. Due to the special relationship with OJV and LNL, the PowerNet **Procurement Policy** (including the **Procurement Strategy**), is implied as also being the procurement practices followed by OJV and LNL. Therefore, the Procurement Policy and Procurement Strategy provided for the purpose of this information disclosure, are as provided by PowerNet.

The **Procurement Policy**, sets the procurement principles for staff to follow when engaging suppliers or sourcing goods and services. The PowerNet **Procurement Strategy** provides guidance on practices and processes for the business to follow when engaging with the suppliers of goods and services, and anywhere the business commits to a purchase obligation.

These documents are to ensure appropriate practices and controls are followed, and to make sure the best value and quality is achieved for the business and stakeholders.

5. APPLICATION OF PROCUREMENT POLICY

ID Determination 2.3.12 (1)

As noted above, the procurement policy and processes adopted by OJV and LNL are based on the PowerNet Procurement Policy and Strategy (FNPO-035). PowerNet and PCL are responsible for sourcing all materials and services required to maintain the OJV and LNL network assets and project manage the replacement or development of new assets. PowerNet recover this expenditure through charging OJV and LNL for capital and maintenance work, and through applying an agency fee for recovering a share of the associated business services costs.

The **Procurement Policy** adopted by OJV and LNL puts emphasis on making decisions in the interest of an asset's lifecycle cost – in particular, capital versus maintenance decisions; considerations when sourcing labour, materials and equipment, and engaging customers for external party works.

The **Procurement Strategy** document covers in detail the applicable processes and practices of purchasing goods and services.

While PowerNet is a related parties of OJV (including LNL) for reporting purposes, they are structured as separate legal entities, operating on an 'arms-length' basis.

Planning

Adequate planning is an important part of the Network's procurement process. Each year the PowerNet Network Asset Engineers prepare the OJV & LNL Asset Management Plan (AMP), a strategic, long-term view of the Network capabilities and constraints. The AMP provides an internal asset management framework for the OJV's network, including the Annual Works Programme (AWP), detailing the capital and operation expenditure (asset maintenance, replacement and/or development) required. The AMP is reviewed and approved by the OJV governing committee and LNL board, prior to the PowerNet Engineers' and Project Managers' developing the AWP, as a key part of the annual business planning process. The AWP translates projects identified in the AMP into categorised work streams with detailed assumptions regarding the timing, materials and resources needed to complete the work, resulting in a more refined cost estimate, for Project Managers' to apply. The AMP is a 10 year view, whilst the AWP focuses on the upcoming 12 month period. In certain cases with large forecasted spend, a project business case is required in advance, for separate Board consideration and approval. The finalised AWP expenditure is included within the OJV & LNL annual business plan approval process.

Project Manager's are assigned to implement the identified projects, within the guidelines of the project budget, and are responsible for managing the resources and making sure the project is completed to required standard.

Where required for high cost projects, or if specialised skills or equipment are required, a 'Request for Tender' process may be undertaken, to provide an indication of market supplier interest and greater certainty of project costs. The PowerNet Tendering Policy provides the steps that are to be followed when work is tendered. The decision to undertake a Tender process will be determined during the project planning phase.

Goods and services will be procured within approved budgets, with any exceptions requiring approval from a Senior Leader or Chief Executive Officer, in line with the financial authority limits. Written cost estimates or quotes are required from Suppliers depending on the value or nature of the job to manage cost expectations.

Resourcing

Having the combined network management of TPCL, EIL, OJV and LNL, gives PowerNet a stronger position to negotiation more favourable competitive prices for goods and services, through the greater purchasing volumes and activity, than would otherwise be possible by OJV and LNL alone. A supplier agreement with Corys Electrical makes it possible to source the required specialised electrical materials at market competitive prices, and the volume of work enables priority response and competitively low prices from many external service providers.

The market of available suppliers of high voltage electrical work in Southland & Otago is very small, and in some cases for specialised tasks, non-existent. PowerNet has learned over the past 25 years through different operating models (from operating with internal field crews, to operating with fully outsourced labour arrangements), the most effective, efficient and reliable outcome for getting OJV & LNL's Works Programme projects completed in a timely manner, to the required standard, is to secure required skills internally, and to apply these staff as needed, across the different networks PowerNet manages.

OtagoNet: In many cases, external contractors are still required for large projects or technically challenging tasks, where resources can be outsourced. Having a team of experienced Line Mechanics and high voltage Technicians enables PowerNet to provide an effective faults response service, reducing the impact on customers of unplanned outages, and helping the OJV network meet its regulatory outage performance targets (SAIDI & SAIFI targets). For this reason, in many cases for OJV network asset maintenance tasks, the work is allocated to PowerNet internal labour teams with the appropriate skills and equipment.

LNL: PowerNet undertakes the majority of the Annual Works Programme projects, whilst outsourcing required services when necessary

While the project resources and materials required are planned by network engineers within the PowerNet Asset Management team, the selection of the Suppliers to provide the work is a responsibility of the respective Project Manager. In making the selection, the Project Manager is mindful of making decisions based on the best outcome on behalf of the network – and so, to protect the value and reliability of the Network Assets, the Project Manager selects the materials and scopes the design to meet the required network design standard. Outsourcing is considered for each element of the project if appropriate, and market testing performed where uncertainties exist in cost or difficulty. This selection process may not always result in the cheapest or easiest short-term option being applied, with decisions made to make sure the outcome is of a high quality and reliable standard, in the best long-term interests of the customers and stakeholders.

Materials are sourced by Corys Electrical who can provide a range of options for the Project Manager to select from, at market competitive prices.

Suitable Contractors must be capable of meeting the operating and health & safety standards of PowerNet, and there are specific controls to check new applicants, to make sure they have completed the requirements (eg. PreQual health & safety assessment) are reputable before allowing them to be selected.

Cost of assets, goods or services from Related Party

The costs PowerNet incurs undertaking the responsibilities of managing OJV and LNL's network assets are charged to OJV & LNL respectively each month. Agreed charges are included within the Network Management Agreement, including monthly progress invoices in relation to the Annual Works Programme project activity expenditure. In return for the management of the network assets and related business support costs, PowerNet charges an Agency fee, and applies an internal commercial mark-up to recover its operating costs and enable a modest commercial profit.

6. PURCHASES REQUIRED FROM A RELATED PARTY

ID Determination 2.3.12 (2)

Activities for which OJV & LNL network customers are required to use PowerNet (related parties) in relation to electricity distribution services are:

- Fault Repairs;
- Requests for a new connection to the network; and
- Removing trees or vegetation from proximity of power lines.

Fault Response and Reactive Maintenance

Under the Network Management Agreement, PowerNet is responsible for maintaining the OJV (including LNL) network assets in good operational order, and in an overall standard equal or better to the initial condition. Returning power to consumers safely and quickly, following a fault or outage event, is an important requirement and performance measure for OJV.

PowerNet provides on-call line mechanics and technicians, located across the Southland and Otago region, able to respond in a very short period of time to a fault call out, to provide a reliable and efficient fault response service, and minimise the impact of a power outage on network customers. Without these remote depot locations the duration (SAIDI) of outages on the OJV network would be adversely affected. Having skilled labour, trained to the network accepted standard and practices, located at various depots across the network, and having appropriate tools and equipment capable of resolving an outage safely and quickly, is a key reason why PowerNet and PowerNet Central provide the fault response services internally, rather than outsourcing.

New Connections

The process for requesting a new connection or capacity upgrade on the OJV (including LNL) network is managed by the PowerNet Distribution team (PowerNet policy FNPO-025 Commercial Terms for New and Altered Customer Connections, or “Connections” policy). This is essential to maintain a consistent design specification standard for the network assets.

As highlighted in the Connections policy, depending on the nature of the customer work required, the Network will likely be required to manage parts of this work, especially where the work involves network equipment being installed or connection being made to Network assets. For high voltage lines installation (11kVA and above), requiring road side access, the Utilities Access Act 2010 controls who has the authorisation to operate in this space, and restricts the access to only approved utility companies. Hence, PowerNet, under the NMA, manages the construction of lines or installation of network equipment along road-sides on behalf of OJV and LNL, or where special easements are required across private land. However, low voltage work on private land is the responsibility of the property owner.

An application must be completed by the customer for the PowerNet Connections team to review and provide an explanation of requirements relating to the work, and any associated costs (in the form of a letter of quotation). The quote must be accepted by the customer prior to PowerNet starting work on behalf of the Network.

If PowerNet are required to undertake construction or installation work, the Project Manager will evaluate what resources are required, and who can do the work. This work may be contracted to an external supplier however due to the small number of high voltage contractors available in Otago this work is often undertaken by the PowerNet Distribution field staff.

The new connection process and responsibilities are explained on the PowerNet website, where details are provided for Customers to use an independent contractor:
https://powernet.co.nz/your-power-supply/getting-connected/

Using an Independent Contractor

It is possible for a consumer to use an independent contractor to design and build part of their new connection. If you are developing a new subdivision or if your new supply is large or remote from the existing network and will require our high voltage network extending across private land you can use an Independent Contractor to carry out some of the work. Further information is available in our Independent Contractor and Developer Reticulation in Subdivisions documents. Please note that there are some statutory tasks that only PowerNet can perform.

Arborist/Tree Management

PowerNet is responsible for vegetation management on the OJV and LNL network, in accordance with the Network Management Agreement. The PowerNet arborist team inspect the network lines and identify areas of risk where trees are growing inside the legal 'growth limit zone'. In these circumstances, PowerNet will notify the tree owners of their obligations by issuing a 'Tree Cut/Trim Notice'. Under the Tree regulations and the network's tree management process – the first cut or trim is at the cost of the network. Following the first cut, the tree owner is responsibility for keeping the tree(s) clear of the 'Growth Limit Zone' around power lines and equipment.

PowerNet provides advice on its website (https://powernet.co.nz/services/trees/) relating to tree regulations and owner's responsibilities, and offers a list of network approved contractors who can undertake tree cutting services on the network for the owner.

The following content can be found on the PowerNet web page, under the services offered:

https://powernet.co.nz/services/trees/approved-contractors/

PowerNet

Approved contractors

Important note:

- *If you choose to organise your own tree cutting and are not using one of our approved contractors (listed below) please call PowerNet System Control on 0800 808 587 at least three days before proceeding to discuss the work to be undertaken.*
- *You or your contractor must apply to work closer than 4m to electric power lines or cables. Click here to complete a close approach permit form and view the close approach permit guidelines.*

Asplundh (Invercargill)

Office on 03 216 8051
Ryan, Contract Manager on 027 662 1999
enquiry@asplundh.co.nz or visit Asplundh www.asplundh.co.nz

Bruce Dickens Tree Topping – Quotes:

Phil, Operations Manager, on 0274 441 008 or 03 212 8686
Bruce on 0274 756 732
Office on 0800 001 165
office@dickenstreetopping.co.nz or visit www.dickenstreetopping.co.nz

Delta – Quotes:

Enquiries phone 03 21516499

Ngaio Rhodes, Tree Service Administrator cell: 021 516400

ngaio.rhodes@thinkdelta.co.nz or visit THINKDELTA.CO.NZ

The Tree Cut/Trim Notice is issued to the tree owner, indicating available options for the work required. The tree owner responds with their preference – either to manage their own contractor, or engage PowerNet.

7. PROCUREMENT REPRESENTATIVE EXAMPLES

ID Determination 2.3.12 (3)

OJV and LNL require a range of services from PowerNet to manage the Network operations. These services may often have very different characteristics and may involve a different procurement process to best suit the situation or work being undertaken. The following list illustrates the categories of transactions with different procurement processes:

i. **Major Construction (Asset Replacement & Renewal)**
Significant large-scale projects are managed by the PowerNet Asset Management – Major Projects team. These projects are often long term (greater than 12 months), complex in design, and usually greater than $1m in cost, with additional procurement requirements. Due to the large amount of dedicated resource and long period of time required, these projects are often subcontracted out by PowerNet.

EXAMPLE: Port Molyneaux Substation Upgrade
The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Major Project' asset development.

Project Name:	Port Molyneaux Substation Outdoor to Indoor Upgrade
Project Date:	2022 - 2024
Project Number:	30959
Total Project Expenditure:	$ 433,000 External labour & materials $ 116,000 PowerNet services --------------- $ 549,000 Total Cost (2022/23)
Expenditure Classification:	Asset Replacement & Renewal
Project Manager:	PowerNet Ltd
Subcontractors:	Energetick Ltd

The Port Molyneux substation is located near the coast at Kaka Point, with the 33kV and 11kV outdoor structures are assessed as being near end of life, and are difficult to access for maintenance. The coastal location increases the vulnerability of the outdoor structure and switchgear to corrosion and salt pollution. This project will replace the 33kV and 11kV outdoor structures with indoor switchgear.

The installation project is ongoing and is planned for completion on 2023/24.

ID Determination 2.3.12 (5)

Market Testing: The majority of this substation upgrade project activity is due to be outsourced by PowerNet. The rates provided by the external contractors were consistent with recent tender prices. The materials sourced through Corys Electrical supply agreement includes a range of contractual mechanisms to ensure efficient prices are being provided to PowerNet. The PowerNet project management and internal labour cost is benchmarked to local market rates.

ii. New Connection / Capacity Upgrade (System Growth)

New connections and capacity upgrades are generally customer driven, whether it be for a new property, or expansion of an existing property. Project size can range from a small connection of a newly built house, to the construction of a new manufacturing plant or new residential subdivisions.

The procurement of goods and services for this type of work follows the same PowerNet procurement processes for a general construction project, only this work is more heavily influenced by a customer need rather than a network need. The PowerNet New Connection policy governs the requirements for this work.

EXAMPLE: Installation of New 100KVA Supply in Ranfurly

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'New Connection' to the OJV network:

Project Name:	Customer Connection (OJV Works programme)
Completion Date:	February 2023
Project Number:	CC 412926 / 409200
Project Expenditure:	$ 32,000 External labour & materials $ 45,000 PowerNet services -------------- $ 77,000 Total Cost (2022/23)
Project Classification:	Consumer Connection (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	Hazlett & Sons (civil works)

PowerNet received an application for an electricity connection in Ranfurly at a supply capacity of 100kVA.

Market Testing: The prices charged by PowerNet have been benchmarked against similar 2021-2023 Line Mechanic or Technician roles from other available external suppliers. Of the $7.4M capital expenditure spent on New Connections and Capacity Upgrades, 64% of this cost related to external labour and materials. The materials sourced through Corys Electrical supply agreement includes a range of contractual mechanisms to ensure efficient prices are being provided to PowerNet.

iii. Distribution & Technical Projects (Asset Replacement and Renewal)

Asset Replacement and Renewal projects are generally driven by internal asset condition and monitoring assessments, performed periodically by PowerNet staff on OJV and LNL network assets. Depending on the nature of the work, this could be a small scale project relating to the replacement of an 11kV Line Pole (eg. 'Red Tag Pole') managed by the PowerNet Distribution Team, or a larger technical project (eg. 500kV transformer replacement or substation upgrade project) managed by the PowerNet Technicians team.

EXAMPLE: LV Line Replacement & Renewal

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Distribution' project for the OJV network:

Project Name:	Replace Poles at Oturehua
Completion Date:	July 2022
Project Number:	CC 391691
Project Expenditure:	$ 10,000 External labour & materials $ 38,000 PowerNet services ------------- $ 48,000 Total Cost (2022/23)
Regulatory Classification:	Asset Replacement & Renewal (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	Chorus Ltd, Hazlett & Sons (civil works)

PowerNet undertook Project CC391691 to replace 11kV and 33kV poles, cross arms and insulators as they were at the end of their useful life, located near the Oturehua Township. This work is identified through PowerNet inspection and testing programmes to identify assets that are reaching the end of their economic life and was deemed essential to maintain security of supply within the area. A PowerNet Project Manager was assigned to plan and oversee the work. Consideration is given to the timing, to make sure resources are available, and to minimise the impact of a power outage to effected OJV customers. PowerNet was assigned to undertake the work, being able to provide the skilled distribution services and equipment required. Materials were sourced through the Corys Supply Agreement.

Market Testing: The prices charged by PowerNet have been benchmarked against similar roles from other external Suppliers utilised during 2021-2023. The materials sourced through Corys Electrical supply agreement includes a range of contractual mechanisms to ensure efficient prices are being provided to PowerNet.

iv. Faults Response (Service interruptions and emergencies)

Fault response is a key service provided by PowerNet and PowerNet Central. Minimising power outage time of network faults, and minimising the number of customers impacted, is an important performance measure of the OJV network (including LNL). As noted above, PowerNet and Powernet Central provide an on-call service, able to respond quickly to an unplanned outage or event. PowerNet Line Mechanics crews are based in depots located across the Southland and Otago regions for quick response to fault call-outs and to minimise travel time across the network. PowerNet Central staff are based in the Central Otago area.

Market Testing: Market prices assumed where PowerNet is applying the same labour rates as applied across other spend categories which are more commonly market tested. The prices charged by PowerNet have been benchmarked against similar Line Mechanic or Technician roles from other external Suppliers utilised during 2022-2023.

v. **Arborist Work (Vegetation Management)**

Tree management costs are driven by work associated to compliance of Government regulations for proximity of branches and vegetation to power lines. OtagoNet is responsible for encouraging property owners to comply with the regulations. PowerNet manages this service on behalf of OtagoNet and operates a skilled vegetation management team. Inspectors identify hazards, liaise with landowners and issue Cut/Trim notices to the landowner as required.

EXAMPLE: Vegetation Management

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for Vegetation Management expenditure on OJV network:

Project Description:	Vegetation Control (OJV Network)
Project Name:	Trim & Fell Trees – Pukeawa 33kV Lines
Project Completion Date:	March 2023
Project Number:	443325
Total Expenditure:	$5,000
Regulatory Classification:	Vegetation Management (Operational Expenditure)
Project Manager:	PowerNet Ltd.
Customer:	OJV Network

Chargeable to OJV Network

The PowerNet Arborist team became aware of hazard trees within the regulatory distance of 33 kV lines near Pukeawa. Details of the location and work required (trees to be trim and felled) were noted on the PowerNet Cut/Trim Notice (CTN 0001611).

In this case, for 'first cut' notification, the work is undertaken by PowerNet and charged to OJV, rather than the property owner.

Market Testing: The vegetation labour and equipment prices charged by PowerNet have been benchmarked against similar arborist roles from other external suppliers where possible.

In the instance where a second cut is required, the property owner is responsible for the cost. In the event that they chose PowerNet as the contractor of choice, the prices are consistent with prices charged to OJV for vegetation work, indicating competitive market rates being applied.

vi. **Business Services (Opex)**

Administration processes and systems associated with running OJV and LNL networks are managed by PowerNet support services teams (eg. Network Assets, Operations, Finance, HSE). A share of these costs are charged to OJV by way of an Agency fee, which would otherwise be directly incurred by OJV, if there was no 'Agency Agreement' (or NMA) in place with PowerNet.

Market Testing: Market testing the provision of business services is very difficult due to the lack of comparability available. However, the benefits of OJV and LNL sharing the cost of running these management and administration systems with other EDB's TPCL and EIL (economy of scale benefits), was recognised in an independent benchmarking exercise in 2018 of PowerNet business and network support services to TPCL/EIL/OJV, against other equivalent sized EDB's on a cost per ICP basis. The findings of the review rated OJV favourably against similar sized EDB's in the same peer group.

APPENDIX B:

NETWORK EXPENDITURE AND CONSTRAINTS

ID Determination 2.3.13 - 2.3.16

Regulatory requirements

- Electricity Distribution Information Disclosure Determination 2012 (Consolidated in 2023), issued 6 July 2023, clauses 2.3.13 to 2.3.16.
- Input methodologies review – related party transactions final decision and determinations guidance 21 December 2017, table 5.1 (copied below, refer to ID for precise requirements).

The purpose of this section is to identify on a map the anticipated network expenditure and network constraints in accordance with the OJV network 2023-2033 Asset Management Plan.

OJV - 10 largest forecast Network Operating Expenditure projects (Maintenance)

- Clause 2.3.13(1), 2.3.14(1) and (2).

The 10 largest forecast Operating Expenditure projects in the 2023-2033 Asset Management Plan for OJV regulated network are explained below, and indicated on the Network map above where relative to a single area:

1. Incident Response – Distribution - $19.06M

   Provision is made for staff, plant and resources to be ready for lines faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers.

2. Vegetation Management - $10.76M

   Annual tree trimming in the vicinity of overhead network is required to prevent contact with lines maintaining network reliability. The first trim of trees has to be undertaken at OJV's expense as required under the Electricity (Hazards from Trees) Regulations 2003.

3. Technical Routine Maintenance - $9.07M

   Routine scheduled maintenance (other than preventative maintenance) on technical assets including planned substation maintenance.

4. Distribution Routine Inspections - $7.70M

   Five yearly network inspections (20% inspected annually), other routine tests and minor maintenance works on distribution assets.

5. Technical Routine Inspections - $2.49M

   Routine inspection and testing of assets at zone substations. Includes such things as oil DGA, breakdown, moisture and acidity, operation counts, protection testing etc. Also covers responses to maintenance triggers, such as oil processing or recalibration of relays.

6. Technical Corrective Maintenance - $2.40M

   Permanent repairs carried out on faulted Technical assets that had temporarily been made safe/functional during the initial incident response.

7. Distribution Routine Maintenance - $2.03M

   Generally reactive work undertaken to correct issues found during the routine distribution inspection. Also a general budget for all minor distribution work.

8. Incident Response – Technical - $2.02M

   Provision is made for staff, plant and resources to be ready for substation faults and emergencies. Fault staff respond to make the area safe, isolate the faulty equipment or network section and undertake repairs to restore supply to all customers.

9. Distribution Corrective Maintenance - $0.94M

   Permanent repairs carried out on faulted Distribution assets that had temporarily been made safe/functional during the initial incident response.

10. Transmission Line Minor Maintenance - $0.94M

    Five-yearly walking condition inspections are made of all subtransmission lines with remedial repairs or renewal planned based on information obtained. Repairs or renewals are planned for all poles whose condition indicates that they are likely to fail before the next inspection.

Further detail relating to OJV network Operating Expenditure is provided in a table at the end of this section.

Please Note: All of these projects -

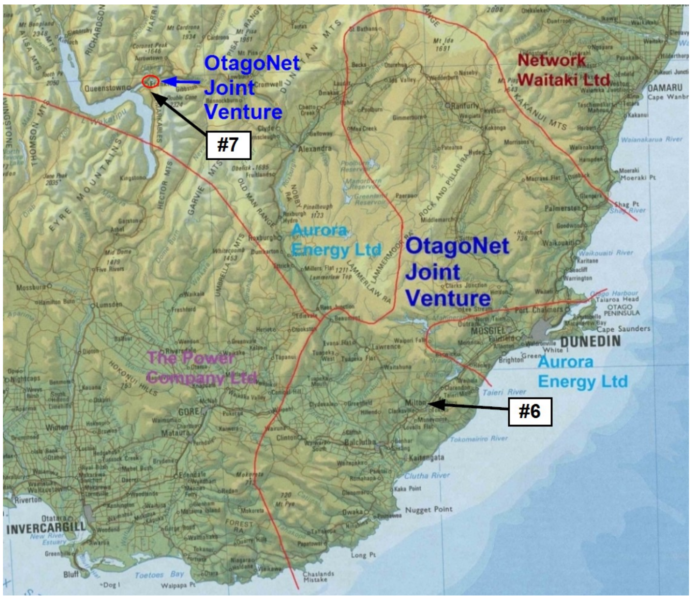
- Are network wide (apply to entire area as shown on map below).
- Have a contract in place that is with PowerNet Limited through a network management agreement (related party).
- Are forecast to require the supply of assets/goods or services by PowerNet Limited (related party).

<u>Possible future constraints related to OJV network Operating Expenditure projects:</u>

There are no identified constraints impacting the network Operating Expenditure budget. All costs are driven by network maintenance requirements and inspection programming.

<u>OJV - 10 largest forecast Network Capital Expenditure projects</u>

- Clause 2.3.13(2), 2.3.14(1) and (2).



The 10 largest forecast Capital Expenditure projects in the 2023-2033 Asset Management Plan for OJV network are explained below, and indicated on the Network map above where relative to a single area:

1. <u>Major New Connection Projects - $44.49M</u>

   Rapid growth areas require a corresponding expansion of the local distribution network. The rate of expansion is somewhat unpredictable as the timing and speed of developments are largely driven by commercial factors outside of OJV's ability to monitor.

   $3.6M has been budgeted under Consumer Connection in the short term for projects that have relative certainty; plus an allowance of approximately $3.7M - $5.0M p.a. in the medium to long term where the location and/or scale of projects is relatively unknown.

2. <u>11 kV Line Replacement and Renewal - $34.79M</u>

   Scheduled for every year, the on-going replacements of 11kV line assets. These are identified through routine inspection. As work is planned based on feeders, this renewal and refurbishment covers distribution lines, cables, dropouts and ABS's. This budget also covers red tagged pole replacement, increasing road crossing height, minor distribution renewals and upgrades.

3. <u>33 kV Line Replacement and Renewal - $20.06M</u>

   33kV line work previously identified through condition assessment that is either on-going or planned. Completion of this work is dependent on customer requirements, land access permission and priority re-assignment as further network condition information becomes available.

4. Unspecified Replacement and Renewal Projects - $9.31M

   The overall objective for replacement and renewal programmes is to get the most out of the network assets by replacing assets as close as possible to their economic end of life. This is balanced by the need to manage workforce resources in the short term and delivery of desired service levels over the long term.

   Inspection and testing programmes identify assets that are reaching the end of their economic life while critical assets may be replaced on a fixed time basis. For example 11kV switchboards at zone substations are replaced at the end of their nominal life. Less critical assets or assets provided with redundancy as part of security arrangements may be run to failure and replaced reactively. Assets such as cables may be run to failure several times and repaired before the fault frequency increases to a point that complete replacement is more economic. This approach requires monitoring of failure rates.

   Apart from whole of lifecycle cost analysis there are several additional drivers for replacement (though they can often be reduced to a cost analysis) including operational or public safety, risk management, declining service levels, accessibility for maintenance, obsolescence and new technology providing options for additional features or alternative solutions.

   This provision is for asset replacement and renewal projects that are yet to be identified and are expected to be implemented in 2028-33.

5. Customer Connections (≤ 20kVA) - $9.06M

   Scheduled for every year, planning for new connections uses averages based on historical trending, modified by any local knowledge if appropriate however customer requirements are generally unpredictable and quite variable. Customers tend not to disclose their intentions until connection is required so cannot be easily planned for in advance. Various options are considered generally to determine the least cost option for providing the new connection. Work required depends on the customer's location relative to existing network and the capacity of that network to supply the additional load. This can range from a simple LV connection at a fuse in a distribution pillar box at the customer's property boundary, to upgrade of LV cables or replacement of overhead lines with cables of greater rating, up to requirement for a new transformer site with associated 11kV extension if required.

6. Tower Road Substation - $8.51M

   The Elderlee Street zone substation feeding Milton is approaching its n-1 capacity and will see a load increase of 0.7 MW when Glenore substation is decommissioned in 2025/26. Including the additional Glenore load, peak load is forecast to exceed n-1 capacity within the ten year planning period.

   Additionally the 11 kV indoor switchgear is approaching end of life, and the substation building has been identified as below current building seismic strength requirements.

   Secondary drivers for replacement include that the present substation is not ideally situated, being in a residential area with potential noise issues and limited room for expansion or renewal. A new site has been secured in Tower Road across the railway line and outside the residential area. Project completion is planned for 2030/31.

7. Southern Corridor Zone Substation - $8.51M

   Rapid growth in the Wakitipu Basin area indicates that a new zone substation will be required in the long term to provide capacity and diversity.

   Establishing a new zone substation will provide for future growth and enhance supply security. The project's planned completion date is 2030/31.

8. LV Line Replacement and Renewal - $8.48M

   Low voltage line work previously identified through condition assessment that is either on-going or planned. Completion of this work is dependent on customer requirements, land access permission and priority re-assignment as further network condition information becomes available.

9. Distribution Transformer Replacements - $6.71M

   On-going replacements of distribution transformers which are generally identified during distribution inspections and targeted inspections based on age. Some removed units are refurbished for use as spares. Also for replacement of distribution transformers removed due to a fault.

10. SWER Line Replacement and Renewal - $5.65M

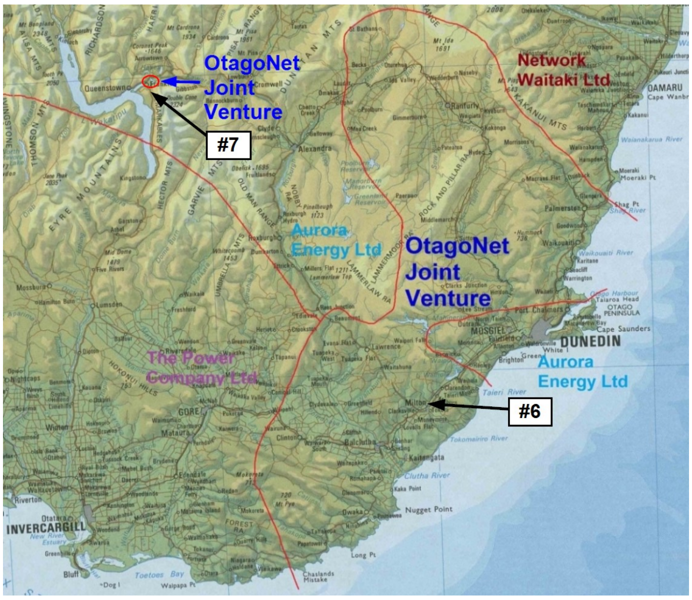
    Single Wire Earth Return line work previously identified through condition assessment that is either on-going or planned over the next 5 years. Completion of this work is dependent on customer requirements, land access permission and priority re-assignment as further network condition information becomes available.

Further detail relating to OJV network Capital Expenditure in a table at the end of this section.

Please Note: All of these projects -

- Are network wide (apply to entire area as shown on map above), except for #8 and #10 which are pinpointed on the map above.
- Have a contract in place that is with PowerNet Limited through an agency agreement (related party).
- Are forecast to require the supply of assets/goods or services by PowerNet Limited (related party).

<u>Possible future constraints related to OJV network Capital Expenditure projects:</u>



The map above indicates where potential future constraints may impact the OJV network performance:

6. Tower Road Substation

   Constraint – Unable to maintain supply voltage due to potential load growth, timing being 5-8 years.

7. Southern Corridor Zone Substation

   Constraint – Unable to maintain supply voltage due to potential load growth, timing being 5-8 years.

OJV - 10 largest forecast Network Operating Expenditure projects (Maintenance)

- Clause 2.3.13(1), 2.3.14(1) and (2).

Project	Project description[1]	Likely timing[2]	Value[3]	Location[4]	Contract in place[5]	Is contract with RP[6]	Forecast to include RP[7]	Currently not indicated for RP[8]
#1	Incident Response - Distribution	Every year	$19.06M	Network Wide	Yes	Yes	Very likely	N/A
#2	Vegetation Management	Every year	$10.76M	Network Wide	Yes	Yes	Very likely	N/A
#3	Technical Routine Maintenance	Every year	$9.07M	Network Wide	Yes	Yes	Very likely	N/A
#4	Distribution Routine Inspections	Every year	$7.70M	Network Wide	Yes	Yes	Very likely	N/A
#5	Technical Routine Inspections	Every year	$2.49M	Network Wide	Yes	Yes	Very likely	N/A
#6	Technical Corrective Maintenance	Every year	$2.40M	Network Wide	Yes	Yes	Very likely	N/A
#7	Distribution Routine Maintenance	Every year	$2.03M	Network Wide	Yes	Yes	Very likely	N/A
#8	Incident Response - Technical	Every year	$2.02M	Network Wide	Yes	Yes	Very likely	N/A
#9	Distribution Corrective Maintenance	Every year	$0.94M	Network Wide	Yes	Yes	Very likely	N/A
#10	Transmission Line Minor Maintenance	Every year	$0.94M	Network Wide	Yes	Yes	Very likely	N/A

OJV - 10 largest forecast Network Capital Expenditure projects

- Clause 2.3.13(2), 2.3.14(1) and (2).

Project	Project description	Likely timing	Value	Location	Contract in place?	Is contract with RP?	Forecast to include RP?	Currently not indicated for RP
#1	Major New Connections Projects	Every year	$44.49M	Network Wide	Yes	Yes	Very likely	N/A
#2	11 kV Line Replacement and Renewal	Every year	$34.79M	Network Wide	Yes	Yes	Very likely	N/A
#3	33 kV Line Replacement and Renewal	Every year	$20.06M	Network Wide	Yes	Yes	Very likely	N/A
#4	Unspecified Replacement & Renewal Projects	Every year	$9.31M	Network Wide	No	N/A	Very likely	N/A
#5	Customer Connections (≤ 20kVA)	Every year	$9.06M	Network Wide	Yes	Yes	Very likely	N/A
#6	Tower Road Substation	2029-2031	$8.51M	#6	No	N/A	Very likely	N/A
#7	Southern Corridor Zone Substation	2029-2031	$8.51M	#7	No	N/A	Very likely	N/A
#8	LV Line Replacement and Renewal	Every year	$8.48M	Network Wide	Yes	Yes	Very likely	N/A
#9	Distribution Transformer Replacements	Every year	$6.71M	Network Wide	Yes	Yes	Very likely	N/A
#10	SWER Line Replacement and Renewal	Every year	$5.65M	Network Wide	Yes	Yes	Very likely	N/A

[1] Clause 2.3.13(1).
[2] Clause 2.3.13(1).
[3] Clause 2.3.13(1).
[4] Clause 2.3.13(1).
[5] Clause 2.3.14(1)(a).
[6] Clause 2.3.14(1)(a).
[7] Clause 2.3.14(1)(b).
[8] Clause 2.3.14(1)(c).

Possible future constraints related to OJV network Capital Expenditure projects:

- Clause 2.3.13(4), 2.3.14(1) and (2).

Description of constraint	Related to Capex project #	Expected timing of constraint
Unable to maintain supply voltage due to potential load growth	#6	5-8 years
Unable to maintain supply voltage due to potential load growth	#7	5-8 years

pwc

Independent Appraiser's Report

To the Governing Committee of OtagoNet Joint Venture, the Directors of Lakeland Network Limited and the Commerce Commission

Independent Appraiser Report on Related Party Transactions Pursuant to Electricity Distribution Information Disclosure Determination 2012

This report is for the OJV Regulatory Network ('the Network') which includes:

- Lakeland Network Limited ('LNL') which operates the LNL network; and
- OtagoNet Joint Venture ('OJV'), consisting of a joint venture between Electricity Invercargill ('EIL') and The Power Company ('TPC'), which operates the OJV network

The Governing Committee for OJV mirrors the Board of LNL. Any reference to the Governing Committee of the Network in this report therefore includes reference to those charged with governance of both OJV and LNL.

We have completed our reasonable assurance engagement in respect of the compliance of OtagoNet Joint Venture (the 'Network') with the related party requirements, as set out in the Electricity Distribution Information Disclosure Determination 2012 (Consolidated) as amended by the Information Disclosure (Non-material) Amendment Determination June 2023, issued by the Commerce Commission on 6 July 2023 (the 'Information Disclosure Determination) for the disclosure year ended 31 March 2023 where we are required to report on:

- Whether the Network's basis for valuation of related party transactions ('valuation of related party transactions'), has complied, in all material respects with clause 2.3.6 of the Electricity Distribution Information Disclosure Determination 2012 (consolidated 6 July 2023) (the 'Information Disclosure Determination'), and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated May 2020) ('the Input Methodologies Determination'); and
- Whether the steps taken by the Network, as specified under the *'Summary of steps and analysis undertaken by the Network to demonstrate compliance'* are considered to be, in all material respects, reasonable in the circumstances.

Opinion

In our opinion:

- the basis for valuation of related party transactions for the disclosure year ended 31 March 2023 complies, in all material respects, with the Information Disclosure Determination and the Input Methodologies Determinations; and
- the steps undertaken by the Network, as specified under the *'Summary of steps and analysis undertaken by the Network to demonstrate compliance'* are considered to be, in all material respects, reasonable in the circumstances.

PricewaterhouseCoopers, The PwC Centre, 60 Cashel Street, PO Box 13244, Christchurch, New Zealand
T: +64 3 374 3000, F: +64 3 374 3001, pwc.co.nz

Basis for opinion

We conducted our engagement in accordance with ISAE (NZ) 3000 (Revised), *Assurance Engagements Other than Audits or Reviews of Historical Financial Information* and SAE 3100 (Revised) *Compliance Engagements* to obtain reasonable assurance that the Network has complied in all material respects with the relevant related party valuations requirements as set out in the Information Disclosure Determination and the Input Methodologies for the year ended 31 March 2023.

In forming our opinion, we have obtained sufficient recorded evidence and all the information and explanations we have required.

Our Approach

Materiality

Our assurance engagement is designed to obtain reasonable assurance about the Network's qualitative and quantitative compliance, in all material respects, with the Information Disclosure Determination and Input Methodologies Determination.

Quantitative materiality level was determined as a percentage of total related party transactions. Qualitative factors were also considered when assessing the arm's length valuation rules on related party transactions.

We used this materiality to determine the scope of our assurance engagement, the nature, timing and extent of our assurance procedures and to evaluate the effect of misstatements, both individually and in aggregate on the related party information as a whole.

Key assumptions we made in carrying out our procedures

In carrying out our procedures as the independent appraiser for the disclosure year ended 31 March 2023, we have relied on the Network's internal controls relating to the identification of related party transactions and the valuation of related party transactions that we tested, and placed reliance on, during our audit of the financial statements for the year ended 31 March 2023.

How we sampled the Network's related party transactions

We obtained the Network's assessment of their compliance with the relevant related party valuation requirements in the Information Disclosure Determination and Input Methodologies Determination.

We selected a sample of related party transactions on a haphazard basis across a range of transactions and services, and agreed these to the supporting information provided by the Network to demonstrate the independent and objective measure used for those transactions and services, to determine whether it has been valued in accordance with the related party valuation requirements in the Information Disclosure Determination and Input Methodologies Determination.

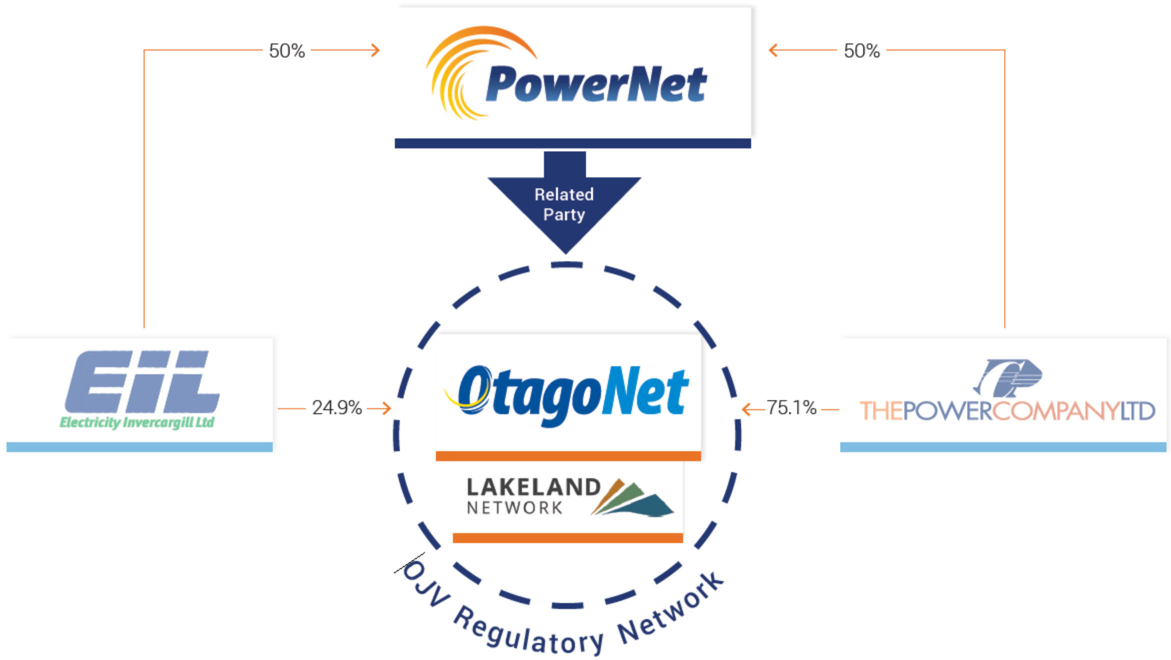
Steps and analysis undertaken in testing compliance

Step 1) Identifying related party relationships and transactions

Summary of steps undertaken by the Network to demonstrate compliance

The Network identified all related party relationships in accordance with the Information Disclosure Determination and disclosed these in Appendix A to the 2023 Information Disclosure Schedules as prepared and published under the Information Disclosure Determination.

The parties to the Network are related. PowerNet Limited ('PowerNet') is a related party due to common ownership. See ownership diagram below:



During the year, related party transactions occurred with PowerNet Limited and The Power Company Limited.

PowerNet Limited:

- PowerNet provides network management services to The Power Company (TPC), OtagoNet Joint Venture (OJV), Electricity Invercargill Ltd (EIL) and Lakeland Network (LLN) , under equivalent Network Management Agreements (NMAs).
- PowerNet subcontracts external parties to assist it in providing these services where appropriate.
- PowerNet recovers its costs from OJV, LNL and the other network companies through an agency fee for network management/business support services, direct pass through of labour and material charges, and a commercial mark-up on capital and maintenance to recover PowerNet's costs and contribute to profit.
- PowerNet also undertakes contestable works for other customers on similar terms.

Related party transactions with PowerNet during the year ended 31 March 2023:

		($000)
Operating Expenditure:		
i.	Service interruptions and emergencies	2,292
ii.	Vegetation management	906
iii.	Routine and corrective maintenance and inspection	2,833
iv.	Asset replacement and renewal (Opex)	180
v.	System operations and network support	794
vi.	Business support	1,882
Total Operating Expenditure		**8,887**

Capital Expenditure:

i.	Consumer connection	7,426
ii.	System growth	1,020
iii.	Asset replacement and renewal (Capex)	10,405
iv.	Asset relocations	383
v.	Quality of supply	195
vi.	Other reliability, safety and environment	722
Total Capital Expenditure		**20,151**
Total Related Party Expenditure		**29,038**

The Power Company:
During the year OJV paid $60,000 to TPC for the rental of specialised equipment. We considered this transaction to be immaterial and no further procedures were performed. No other related party transactions occurred between TPC and OJV.

Our Procedures Undertaken

We have tested the completeness and accuracy of the related party relationships and transactions by:

- Agreeing the disclosures within Appendix A and Schedule 5b of the 2023 Information Disclosure schedules to the audited financial statements for the year ended 31 March 2023 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 the Input Methodologies Determination clause 1.1.4(2) (b) to assess OJV and LNL's identification of any " unregulated parts" of the entities respectively.

Step 2) Outlining the intent behind the agency agreement with PowerNet

Summary of steps undertaken by the Network to demonstrate compliance

OJV (including LNL) incurs 100% of its capital expenditure and the majority of operating costs from PowerNet, for operating its electricity distribution businesses. PowerNet operates in accordance with the explicit terms and conditions of a Network Management Agreement (NMA).

While OJV & LNL own the Network distribution assets and provide electricity distribution services through their respective electricity networks in the Clutha and Central Otago region, under the NMA agreement PowerNet manages the maintenance, replacement or development activity associated with network assets, in accordance with an approved annual Capital and Maintenance Works programme. PowerNet has the exclusive right to provide Line Function Services, and also provide the business administration services on behalf of OJV and LNL.

PowerNet was established in 1994 to extract operational efficiencies from the merger of field work management, asset management and office based functions performed by TPCL and EIL. In 1993, there were two autonomous Lines Companies in Southland (TPCL and EIL). 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 2018 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 network 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 metering 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.

Our Procedures Undertaken

The background information provided by the Network is in line with our understanding of the intent behind the group structure and agency/ management agreement between the Network and PowerNet.

We obtained the minutes of board meetings and noted:

- A focus on ensuring efficient cost and effective management of the network with regular measurement of performance and monitoring in the monthly board reports;
- Approval of the NMA and annual business plan by the both the OJV Governing committee and the Lakeland Board;
- External reports obtained and presented to the OJV Governing committee and the Lakeland Board on prudency and efficiency of forecast spends and benchmarking of operational cost efficiency; and
- An independent report obtained focussed on the appropriate allocation of PowerNet costs between the four network customers.

We obtained all PowerNet's NMAs and note the agreements are consistent for TPC, EIL, LLN and OJV. This equivalence demonstrates that the transactions with OJV and LNL are consistent with the regional market.

Step 3) Assessing compliance with the definition of an arm's length transaction (in accordance with ISA (NZ) 550

From 1 April 2018, a principles - based approach to the valuation of related party transactions is being applied. All related party transactions must meet the arm's length valuation rule for ID disclosures, based on the following definition of arm's length transaction from the iternational Standard for Auditing (NZ) 550: *"a transaction conducted on such terms and conditions as between a willing buyer and a willing seller who are unrelated and are acting independently of each other and pursuing their own best interests"*.

Summary of steps undertaken by the Network to demonstrate compliance

The Network acknowledges that meeting the 'arm's length' valuation criteria, as defined above, is challenging due to the ownership structure and significant amount of work PowerNet manages on behalf of OJV and LNL under their respective NMA's.

OJV and LNL performed an analysis of the arm's length definition and have set out its interpretation in Appendix A to the 2023 Information Disclosure Schedules. Key points are summarised below:

i. *Terms and conditions*
The Network's purchasing terms and conditions applied to PowerNet, are the same as applied to other suppliers. In turn, the purchasing terms and conditions PowerNet applies, are the same to OJV and LNL as any other customer.

ii. *Willing buyer and willing seller who are unrelated*
The internal labour rates applied, and commercial mark-up rates are the same to the Network and all other customers for similar services, indicating that the parties are acting consistent with the principle of willing buyer and willing seller who are unrelated.

iii. *Acting independently*
The Network is related to PowerNet by way of common ownership, however with regards to acting independently, PowerNet operates with the level of independence of a separate entity as the ownership is held by two shareholders with differing ownership structures. Each entity has its own Governing Committee/Board of Directors who act independently in their roles.

iv. *Pursuing their own best interests*
Both shareholders of PowerNet have different ownership structures (TPC owned by a Consumer Trust and EIL is owned by the Invercargill City Council) and different regulatory requirements. This unrelated ownership ensures a review process when preparing budgets and analysing performance, to make sure one shareholder is not disadvantaged over the other with each entity pursuing their own best interest.

Our Procedures Undertaken

PowerNet performed 100% of OJV and LNL's capital expenditure and 89% of OJV and LNL's operating expenditure for the year ended 31 March 2023. Whilst PowerNet performs the majority of OJV and LNL's capital and operating expense work, we note that 25% of the costs related to external materials and labour (Excl. mark ups) obtained at an arm's length.

We have performed the following procedures over the Networks arm's length definition assessment:

i. *Terms and conditions*
Agreed the TPC standard terms and conditions to the PowerNet standard terms and conditions (applied to both OJV, LNL and external customers) and noted no variation.

ii. *Willing buyer and willing seller who are unrelated*
Obtained copies of contracts with unrelated PowerNet customers and confirmed the internal labour rate and commercial mark-up to that which is charged to OJV and LNL is at or below the charges to external customers.

iii. *Acting independently*
We note that the PowerNet Board has obligations to all of its customers, through its terms and conditions of supply. From a PowerNet perspective, Directors must meet their fiduciary duties by honouring those obligations. They cannot favour OJV and LNL because PowerNet has multiple customers.

iv. *Pursuing their own best interests*
We considered evidence obtained through our other procedures which indicates how each entity pursues its own best interest below:

How does PowerNet pursue its own best interests?

- It ensures all customers have the same terms of trade;
- It seeks customer approval of its annual works programme;
- It sub-contracts work where there are better outcomes for its customers; and
- It negotiates wholesale purchase agreements to minimise costs.

How does OJV and LNL pursue their own best interests?

- They ensure PowerNet's other customers do not receive favourable terms;
- They monitor the performance of PowerNet; and
- They approve PowerNet's work plans for its network.

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Step 4) Obtaining independence and object measures to support the arm's length principle

Summary of steps undertaken by the Network to demonstrate compliance

The independent and objective measures used by the Network to demonstrate prices paid are no more than arm's length transaction value are as follows.

External labour & materials (opex and capex)

- Sourced from external suppliers, on a traditional arm's length basis
- Cost efficiencies gained through supplier agreements e.g. electrical supply agreements ensure prices are no more than market rates due to wholesale agreements consistent with the scale of PowerNet's operations

Mark-up external labour & materials (opex)

- Cost efficiencies gained through economies of scale
- Transparency of cost allocation process based on cost drivers and consistent mark-up rates for customers
- External non-network customer work being awarded to PowerNet based on the same opex rates as charged to Electricity Distribution Business (EDB) customers

Mark-up external labour and materials (capex)

- Cost efficiencies gained through economies of scale
- Transparency of cost allocation process based on cost drivers and consistent mark-up rates for customers
- External non-network customer work being awarded to PowerNet based on the same capex rates as charged to Electricity Distribution Business (EDB) customers

Internal labour & equipment charges (opex and capex)

- Unit rates are consistent for each EDB and PowerNet's other customers
- Labour rates are benchmarked against competitors, and fall within expected ranges
- Independent engineer review of prudency and efficiency of works programme previously completed

Business, system, network support (opex)

- Shared services model provides scale efficiencies to TPC
- Share of PowerNet's costs assigned to TPC based on measurable and transparent cost drivers, applied consistently across all of PowerNet's customers

Our procedures undertaken

We obtained the Network's assessment of the available independent and objective measures used in supporting the arm's length valuation principle.

We noted that procedures are in place for monitoring of costs. We performed the following procedures over a sample of transactions at the work order level:

- Agreed the make-up of costs (as reported by the Network above) to the work order within the Tech1 system;
- Agreed individual costs to supporting invoices from external suppliers) or agreed rates (such as labour rates);
- Agreed the internal labour rates and mark-ups charged to those used in the labour rates benchmarking analysis;
- Tested appropriate approval of project costs at completion of the project by the project manager; and
- Tested compliance with the procurement policy/processes disclosed in Appendix A to the Information Disclosure Schedules.

We performed the following procedures on the individual components of costs as outlined by the Network to gain comfort over the appropriateness of and level of comfort obtained from the independent and objective measures provided:

External labour & materials (Opex $1.6m and Capex $10.2m)

- Obtained a copy of the electrical supply agreement, which covers a significant portion of the costs and noted quarterly reviews of prices and performance; and
- Agreed external costs, for a sample of work orders, to supporting invoices from external suppliers.

Mark-up external labour & materials (Opex $0.9m and Capex $4.7m)

- Obtained the NMA and minutes of OJV's Governing Committee and LNL's Board of Directors and noted approval of all cost allocation methods;
- Obtained mark-up comparison published documentation between three competitors, noting consistent external contractor services and materials rates
- Obtained all of the PowerNet NMAs and note consistent terms and mark-up rates are applied to PowerNet's EDB customers; and
- Obtained PowerNet's contracting mark-up rates for a sample of external customer projects undertaken during the year and note mark-up rates applied to PowerNet's EDB customers are at or below those market rates charged to external customers.
- Obtained the capital project indirect labour allocation analysis and tested a sample of the inputs to supporting documentation and verified the nature of tasks performed and estimated FTE allocation through interviews with a sample of employees.

Internal labour & equipment charges (Opex $5.2m and Capex $3.7m)

- We obtained subsequent benchmarking performed by the Network over opex and capex labour and equipment rates;
- Agreed PowerNet labour and equipment rates to a sample of work orders to ensure they agree to rates charged to the Network during the year;
- Agreed market/competitor rates to supporting documentation such as quotes or invoices;

- Recalculated the variances and average percentages between PowerNet rates and other market rates;
- Considered the reasonableness of the variance of labour rates between PowerNet and market rates and accept the PowerNet rates as within an acceptable range when compared to the industry benchmarking performed by the Network. The majority of the rates are below the benchmarked market rates with the remaining rates considered within an acceptable range of up to 15%.

Business, system & network support (Opex $2.7m)

- Obtained a copy of the NMA and understood how costs are recovered through the agency fee;
- Obtained the NMA and minutes of board meetings and note approval by the TPC board of the agency fee;
- Obtained the business plans for FY22/23 and note approval by the OJV Governing Committee and LNL Board of the basis for allocation of the agency fee;
- Obtained benchmarking performed on business and system support costs through the use of the historic information disclosure schedules and note the Network's business and system support costs per Installation Control Point (ICP) rate well in comparison to its peer group (by size and ICP density).

Director's Responsibilities

The Directors are responsible on behalf of the Network for:

- the identification of related-parties and related- party transactions during the disclosure year ended 31 March 2023;
- compliance with the Information Disclosure Determination and the valuation of related party transactions in accordance with the Information Disclosure Determination and the Input Methodologies Determination; and
- the identification of risks that threaten such compliance and controls which will mitigate those risks and monitor ongoing compliance.

Appraisers' Responsibilities

Our responsibility is to prepare an independent appraiser report in accordance with clause 2.8.4 of the Information Disclosure Determination. In preparing the report we are required to express an opinion on whether, for the disclosure year ended 31 March 2023, the basis for valuation of related party transactions complies, in all material respects, with the Information Disclosure Determination and the Input Methodologies Determination, and whether the steps taken by the Network to test whether it complies, are considered to be, in all material respects, reasonable in the circumstances.

Our engagement has been conducted in accordance with ISAE (NZ) 3000 (Revised), Assurance Engagements Other than Audits or Reviews of Historical Financial Information and SAE 3100 (Revised) Compliance Engagements which require that we plan and perform our procedures to obtain reasonable assurance.

An assurance engagement to report on the Network's compliance with the Information Disclosure Determination and the Input Methodologies Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the relevant related party valuation requirements of the Information Disclosure Determination and the Input Methodologies Determination. The procedures selected depend on our judgement, including the identification and assessment of risks of material non- compliance with the relevant related party valuation requirements of the Information Disclosure Determination and the Input Methodologies Determination.

Our Independence and Quality Management

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

We apply Professional and Ethical Standard 3 Quality Management for Firms that Perform Audits or Reviews of Financial Statements, or Other Assurance or Related Services Engagements, which requires our firm to design, implement and operate a system of quality management including policies or procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

We are independent of the Network. Our firm carries out other services for the Network in the areas of compliance with the Electricity Distribution Services Default Price-Quality Path Determination 2020 and the Electricity Distribution (Information Disclosure) Determination 2012, financial statement audit, provision of regulatory advisory services, and other regulatory requirements of the Commerce Act 19866. The provision of these other services has not impaired our independence.

Inherent Limitation

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

A reasonable assurance engagement for the disclosure year ended 31 March 2023 does not provide assurance on whether compliance with the relevant related party valuation requirements of the Information Disclosure Determination and the Input Methodologies Determination will continue in the future.

Use of this report

This independent assurance report has been prepared solely for the Governing Committee of OtagoNet Joint Venture and the Board of Directors Lakeland Network Limited and for the Commerce Commission for the purpose of providing those parties with reasonable assurance on whether:

- the Networks' related party transactions for the disclosure year ended 31 March 2023, comply, in all material respects, with clause 2.3.6 of the Information Disclosure Determination and clauses 2.2.11(1) (g) and 2.2.11(5) of the Input Methodologies Determination; and
- the steps taken by the Network, as specified under the "Summary of steps and analysis undertaken by the Network to determine compliance" are considered to be, in all material respects, reasonable in the circumstances. We disclaim any assumption of responsibility for any reliance on this report to any person other than the directors of the Network or the Commerce Commission, or for any other purpose than that for which it was prepared.

The engagement partner on the assurance engagement resulting in this independent appraiser's report is Elizabeth Adriana (Adri) Smit, who is a licensed auditor with the New Zealand Institute of Chartered Accountants which forms part of Chartered Accountants Australia and New Zealand.

PricewaterhouseCoopers.

PricewaterhouseCoopers
31 August 2023

Independent Assurance Report

To the Governing Committee of OtagoNet Joint Venture and the Commerce Commission

Assurance report pursuant to Electricity Distribution Information Disclosure Determination 2012 (Consolidated 6 July 2023)

We have completed the reasonable assurance engagement in respect of the compliance of OtagoNet Joint Venture (the "Joint Venture") with the Electricity Distribution Information Disclosure Determination 2012 (consolidated 6 July 2023) (the 'Determination') for the disclosure year ended 31 March 2023 where we are required to opine on:

- whether the Joint Venture has complied, in all material respects, with the Determination, in preparing the information disclosed under schedules 1 to 4, 5a to 5g, 6a and 6b, 7, 10, the related party transactions information disclosed in Appendix A, and the explanatory notes disclosed in boxes 1 to 11 in Schedule 14 ('the Disclosure Information'); and
- whether the Joint Venture's basis for valuation of related party transactions ('valuation of related party transactions'), has complied, in all material respects, with clause 2.3.6 of the Determination and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 (consolidated 20 May 2020) ('the IM Determination').

This assurance report should be read in conjunction with the Commerce Commission's Information Disclosure exemption, issued to all electricity distribution businesses on 26 May 2023 under clause 2.11 of the Determination. The Commerce Commission granted an exemption from the requirement that the assurance report, in respect of the information in Schedule 10 of the Determination, must take into account any issues arising out of the Joint Venture's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

Qualified Opinion

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

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

Basis for Qualified Opinion

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

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

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

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

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

Our assurance approach

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

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

- Financial information – any impact resulting in +/-100 basis points of the Return of Investment ('ROI')

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

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

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

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

We have determined that there are two key assurance matters:

- Regulatory Asset Base
- Related Party Transactions

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

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

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

These procedures have been undertaken to form an opinion as to whether the Joint Venture has complied, in all material respects, with the Determination in the preparation of the Disclosure Information for the year ended 31 March 2023, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

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

Key Assurance Matter	How our procedures addressed the key assurance matter
Regulatory asset base The Regulatory Asset Base (RAB), as set out in Schedule 4, reflects the value of OtagoNet Joint Venture's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination. It is a measure which is used widely and is key to measuring OtagoNet Joint Venture's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the IM Determination, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Determination and the IM Determination. Our procedures over the regulatory asset base included the following: **Assets commissioned** ● We considered the nature of the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Determination, which are required to be removed from the RAB; ● We reconciled the assets commissioned, as per the regulatory fixed asset register, to the asset additions disclosed in the audited annual financial statements and investigated any material reconciling items; and ● We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification.

Key Assurance Matter	How our procedures addressed the key assurance matter
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.	**Depreciation** ● We compared the spreadsheet formula utilised to calculate regulatory depreciation expense with IM Determination clause 2.2.5; ● We compared the standard asset lives by asset category to those set out in the IM Determination; and ● We have performed a reasonableness test to ensure regulatory depreciation expense is calculated in line with IM Determination clause 2.2.5. **Revaluation** ● We recalculated the revaluation rate set out in the IM Determination using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; and ● We tested the mathematical accuracy of the revaluation calculation performed by management. **Disposals** ● We reconciled the disposals, as per the regulatory fixed asset register, to the asset disposals disclosed in the audited annual financial statements and investigated any material reconciling items; and ● We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the IMs;
Related party transactions Disclosures over related party transactions including related party relationships, procurement policies/processes, application of these policies/processes and examples of market testing of transaction terms as required under the Determination and the IM Determination are set out in Appendix A. The Determination and the IM Determination require the Joint Venture 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	We have obtained an understanding of the compliance requirements relevant to related party transactions as set out in the Determination and the IM Determination. We have ensured Schedule 5(b) and Appendix A includes all required disclosures including current procurement policies, descriptions of how they are applied in practice, representative example transactions and when and how market testing was last performed. Our procedures over the related party transactions included the following: **Completeness and accuracy of related party relationships and transactions** We have tested the completeness and accuracy of the related party relationships and transactions by: ● Agreeing the disclosures within Schedule 5(b) to the audited financial statements for the year ended 31 March 2023 and to the accounting records, investigating any material differences and determining whether any such differences are justified; and ● Applying our understanding of the business structure against the related party definition in IM Determination

Key Assurance Matter	How our procedures addressed the key assurance matter
valued at an amount less than if it had been sold or supplied under the terms of an arm's-length transaction with an unrelated party. Arm's-length valuation, as defined in the IM Determination, is the value at which a transaction, with the same terms and conditions, would be entered into between a willing seller and a willing buyer who are unrelated and who are acting independently of each other and pursuing their own best interests.OtagoNet Joint Venture 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.	clause 1.1.4(2)(b) to assess management's identification of any "unregulated parts" of the entity. **Practical application of procurement policies** ● Testing a sample of operating expenditure and capital expenditure transactions disclosed in Schedule 5(b) by inspecting supporting documentation to determine compliance with the disclosed procurement policy and practices. **Arm's length valuation rule** We obtained OtagoNet Joint Venture's assessment of available independent and objective measures used in supporting the arm's length valuation principal and performed the following procedures: ● Re-performed the calculations within OtagoNet Joint Venture's benchmarking assessment and agreed key inputs and assumptions to supporting documentation; ● Where benchmarking or other market information was used as independent and objective measures, we assessed whether the related party transaction values fell within a reasonable range. Qualitative factors were considered in determining the appropriate acceptable range.

Governing Committee's Responsibilities

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

Our Independence and Quality Control

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

In accordance with the Professional and Ethical Standard 3 (Amended) *Quality Control for Firms that Perform Audits and Reviews of Financial Statements, and Other Assurance Engagements* or other professional requirements, or requirements in law or regulation, that are at least as demanding, our firm maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements.

We are independent of OtagoNet Joint Venture. Our firm carries out other services for the Joint Venture in the areas of compliance with the Electricity Distribution Services Default Price-Quality Path Determination 2020 and the Electricity Distribution (Information Disclosure) Determination 2012, financial statement audit, provision of regulatory advisory services, and other regulatory requirements of the Commerce Act 1986. The provision of these other services has not impaired our independence.

Assurance Practitioner's responsibilities

Our responsibility is to express an opinion on whether the Joint Venture has complied, in all material respects, with the Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2023 and on whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

Our engagement has been conducted in accordance with ISAE (NZ) 3000 (Revised) and SAE 3100 (Revised) which require that we plan and perform our procedures to obtain reasonable assurance about whether the Joint Venture has complied in all material respects with the Determination in the preparation of the Disclosure Information for the disclosure year ended 31 March 2023, and whether the basis for valuation of related party transactions complies, in all material respects, with the Determination and the IM Determination.

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

Inherent Limitations

Because of the inherent limitations of an assurance engagement, together with the internal control structure, it is possible that fraud, error or non-compliance may occur and not be detected. A reasonable assurance engagement for the disclosure year ended 31 March 2023 does not provide assurance on whether compliance with the Determination and the IM Determination will continue in the future.

Use of Report

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

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

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

PricewaterhouseCoopers

Chartered Accountants
31 August 2023

Christchurch, New Zealand

6. Directors' Certificate

Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Peter William Moynihan and James Albert Carmichael, being governing committee members of OtagoNet Joint Venture 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 OtagoNet Joint Venture'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.

Peter William Moynihan **James Albert Carmichael**

31 August 2023

Footnote:
The Governing Committee of OtagoNet Joint Venture (OtagoNet) note the amendment to the Information Disclosure exemption: Disclosure and auditing of reliability information within Schedule 10, issued by the Commerce Commission on 26 May 2023 that has removed the auditor report requirements relating to the treatment of successive interruptions for reporting SAIDI, SAIFI, and interruptions, because of potential inconsistencies in treatment approaches across the industry.

Members 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 OtagoNet network has recorded successive interruptions, originating from the same cause, as single interruptions.