THE POWER COMPANY LTD

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

FOR THE YEAR ENDED 31 MARCH 2023

CONTENTS

1. INTRODUCTION

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

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

2. INFORMATION DISCLOSURE DISCLAIMER

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

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

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

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

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

3. SCHEDULES

Company Name **The Power Company Limited**
For Year Ended **31 March 2023**

SCHEDULE 1: ANALYTICAL RATIOS

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

sch ref

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**	21,719	479	111,700	2,011	37,407
10	Network	13,185	291	67,810	1,221	22,709
11	Non-network	8,534	188	43,889	790	14,698
12						
13	**Expenditure on assets**	39,197	864	201,584	3,630	67,508
14	Network	39,197	864	201,584	3,630	67,508
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**	72,912	1,607
20	Standard consumer line charge revenue	83,595	1,449
21	Non-standard consumer line charge revenue	33,606	984,457
22			

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

sch ref			
24			
25	Demand density	18	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	93	*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	22,035	*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	17,864	29.63%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	13,429	22.27%
34	Total depreciation	17,599	29.19%
35	Total revaluations	30,336	50.32%
36	Regulatory tax allowance	3,648	6.05%
37	Regulatory profit/(loss) including financial incentives and wash-ups	37,655	62.46%
38	**Total regulatory income**	60,288	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	20.61	*Interruptions per 100 circuit km*

Company Name	The Power Company Limited
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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				
7	**2(i): Return on Investment**	**CY-2**	**CY-1**	**Current Year CY**
8				
9	**ROI – comparable to a post tax WACC**	**%**	**%**	**%**
10	Reflecting all revenue earned	3.17%	8.66%	8.15%
11	Excluding revenue earned from financial incentives	3.17%	8.66%	8.15%
12	Excluding revenue earned from financial incentives and wash-ups	3.17%	8.66%	8.15%
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	3.50%	8.96%	8.66%
21	Excluding revenue earned from financial incentives	3.50%	8.96%	8.66%
22	Excluding revenue earned from financial incentives and wash-ups	3.50%	8.96%	8.66%
23				
24	**WACC rate used to set regulatory price path**	NA	NA	NA
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	457,373		
33	*plus* Opening deferred tax	(25,243)		
34	**Opening RIV**		432,130	
35				
36	**Line charge revenue**		59,970	
37				
38	Expenses cash outflow	31,293		
39	*add* Assets commissioned	22,097		
40	*less* Asset disposals	834		
41	*add* Tax payments	1,448		
42	*less* Other regulated income	318		
43	**Mid-year net cash outflows**		53,686	
44				
45	**Term credit spread differential allowance**		431	
46				
47	Total closing RAB value	491,373		
48	*less* Adjustment resulting from asset allocation	0		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(27,442)		
51	**Closing RIV**		463,931	
52				
53	**ROI – comparable to a vanilla WACC**			8.66%
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**			8.15%

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	8.50%
Year-end ROI – comparable to a post tax WACC	7.98%

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

2(v): Financial Incentives and Wash-Ups

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

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SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

sch ref			($000)
7		**3(i): Regulatory Profit**	($000)
8		**Income**	
9		Line charge revenue	59,970
10	*plus*	Gains / (losses) on asset disposals	(791)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	1,109
12			
13		**Total regulatory income**	60,288
14		**Expenses**	
15	*less*	Operational expenditure	17,864
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	13,429
18			
19		**Operating surplus / (deficit)**	28,995
20			
21	*less*	Total depreciation	17,599
22			
23	*plus*	Total revaluations	30,336
24			
25		**Regulatory profit / (loss) before tax**	41,733
26			
27	*less*	Term credit spread differential allowance	431
28			
29	*less*	Regulatory tax allowance	3,648
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	37,655
32			

		($000)	
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	($000)	
34	**Pass through costs**		
35	Rates	280	
36	Commerce Act levies	140	
37	Industry levies	151	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	12,593	
41	Transpower new investment contract charges	265	
42	System operator services	–	
43	Distributed generation allowance	–	
44	Extended reserves allowance	–	
45	Other recoverable costs excluding financial incentives and wash-ups	–	
46	**Pass-through and recoverable costs excluding financial incentives and wash-ups**		13,429
47			

48	**3(iii): Incremental Rolling Incentive Scheme**		($000)	
49			CY-1	CY
50				31 Mar 23
51	Allowed controllable opex		–	–
52	Actual controllable opex		–	–
53				
54	Incremental change in year			–
55				
56			Previous years' incremental change	Previous years' incremental change adjusted for inflation
57	CY-5	[year]	–	–
58	CY-4	[year]	–	–
59	CY-3	[year]	–	–
60	CY-2	[year]	–	–
61	CY-1	[year]	–	–
62	**Net incremental rolling incentive scheme**			–
63				
64	**Net recoverable costs allowed under incremental rolling incentive scheme**			–

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

69	**3(v): Other Disclosures**	
70		($000)
71	Self-insurance allowance	–

Company Name	The Power Company Limited
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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)

sch ref		RAB CY-4 ($000)	RAB CY-3 ($000)	RAB CY-2 ($000)	RAB CY-1 ($000)	RAB CY ($000)
7						
8						
9						
10	**Total opening RAB value**	373,678	385,009	407,982	420,819	457,373
11						
12	*less* **Total depreciation**	13,762	14,313	15,236	15,969	17,599
13						
14	*plus* **Total revaluations**	5,526	9,710	6,184	28,991	30,336
15						
16	*plus* **Assets commissioned**	20,360	28,192	22,706	24,308	22,097
17						
18	*less* **Asset disposals**	792	616	818	777	834
19						
20	*plus* **Lost and found assets adjustment**	–	–		–	–
21						
22	*plus* **Adjustment resulting from asset allocation**					0
23						
24	**Total closing RAB value**	385,009	407,982	420,819	457,373	491,373
25						

4(ii): Unallocated Regulatory Asset Base

sch ref		Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
26					
27					
28					
29	**Total opening RAB value**		457,373		457,373
30	*less*				
31	**Total depreciation**		17,599		17,599
32	*plus*				
33	**Total revaluations**		30,336		30,336
34	*plus*				
35	Assets commissioned (other than below)	–		–	
36	Assets acquired from a regulated supplier	–		–	
37	Assets acquired from a related party	22,097		22,097	
38	**Assets commissioned**		22,097		22,097
39	*less*				
40	Asset disposals (other than below)	834		834	
41	Asset disposals to a regulated supplier	–		–	
42	Asset disposals to a related party	–		–	
43	**Asset disposals**		834		834
44					
45	*plus* **Lost and found assets adjustment**		–		–
46					
47	*plus* **Adjustment resulting from asset allocation**				0
48					
49	**Total closing RAB value**		491,373		491,373

** 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.*

50

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 *		RAB	
		($000)	($000)	($000)	($000)
	Total opening RAB value	457,373		457,373	
less	Opening value of fully depreciated, disposed and lost assets	1,527		1,527	
	Total opening RAB value subject to revaluation	455,845		455,845	
	Total revaluations		30,336		30,336

4(iv): Roll Forward of Works Under Construction

		Unallocated works under construction		Allocated works under construction	
	Works under construction—preceding disclosure year		8,349		8,349
plus	Capital expenditure	22,462		22,462	
less	Assets commissioned	22,097		22,097	
plus	Adjustment resulting from asset allocation				
	Works under construction - current disclosure year		8,714		8,714
	Highest rate of capitalised finance applied				

4(v): Regulatory Depreciation

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Depreciation - standard	17,599		17,599	
Depreciation - no standard life assets	–		–	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		17,599		17,599

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	62,844	4,567	119,733	157,217	21,038	59,354	24,390	8,229	–	457,373
less	Total depreciation	2,077	120	4,522	6,968	760	1,921	936	295	–	17,599
plus	Total revaluations	4,178	307	7,998	10,395	1,390	3,876	1,644	549		30,336
plus	Assets commissioned	1,779	794	3,177	7,654	562	1,780	5,947	404	–	22,097
less	Asset disposals	–	–	205	–	–	628	1	–	–	834
plus	Lost and found assets adjustment										–
plus	Adjustment resulting from asset allocation										–
plus	Asset category transfers										–
	Total closing RAB value	66,724	5,548	126,181	168,298	22,230	62,461	31,044	8,887	–	491,373
	Asset Life										
	Weighted average remaining asset life	35.8	37.9	32.3	24.6	42.1	32.8	27.2	16.0	–	(years)
	Weighted average expected total asset life	57.5	45.4	45.2	58.6	61.6	47.3	39.2	32.6	–	(years)

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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**		41,733	
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	1		*
12		Amortisation of initial differences in asset values	6,934		
13		Amortisation of revaluations	2,992		
14				9,927	
15					
16	*less*	Total revaluations	30,336		
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	95		*
20		Notional deductible interest	8,203		
21				38,634	
22					
23		**Regulatory taxable income**		13,027	
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income		13,027	
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**		3,648	
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	104,017		
37	*less*	Amortisation of initial differences in asset values	6,934		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	191		
40		Closing unamortised initial differences in asset values		96,892	
41					
42		Opening weighted average remaining useful life of relevant assets (years)		15	
43					

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	381,911	
	Adjusted depreciation	14,607	
	Total depreciation	17,599	
	Amortisation of revaluations		2,992

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	(25,243)	
plus	Tax effect of adjusted depreciation	4,090	
less	Tax effect of tax depreciation	5,058	
plus	Tax effect of other temporary differences*	634	
less	Tax effect of amortisation of initial differences in asset values	1,942	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–	
less	Deferred tax balance relating to assets disposed in the disclosure year	(77)	
plus	Deferred tax cost allocation adjustment	(0)	
	Closing deferred tax		(27,442)

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	198,676	
less	Tax depreciation	18,063	
plus	Regulatory tax asset value of assets commissioned	24,475	
less	Regulatory tax asset value of asset disposals	290	
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		204,798

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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			
7	**5b(i): Summary—Related Party Transactions**	**($000)**	**($000)**
8	**Total regulatory income**		38
9			
10	**Market value of asset disposals**		–
11			
12	Service interruptions and emergencies	4,367	
13	Vegetation management	1,380	
14	Routine and corrective maintenance and inspection	4,456	
15	Asset replacement and renewal (opex)	642	
16	**Network opex**		10,845
17	Business support	3,045	
18	System operations and network support	2,249	
19	**Operational expenditure**		16,138
20	Consumer connection	13,101	
21	System growth	3,278	
22	Asset replacement and renewal (capex)	11,263	
23	Asset relocations	285	
24	Quality of supply	576	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	3,735	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		32,239
29	Cost of financing		–
30	Value of capital contributions		–
31	Value of vested assets		–
32	**Capital Expenditure**		32,239
33	**Total expenditure**		48,377
34			
35	**Other related party transactions**		–

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

37	**Name of related party**	**Nature of opex or capex service provided**	**Total value of transactions ($000)**
38	PowerNet Limited	Service interruptions and emergencies	4,367
39	PowerNet Limited	Vegetation management	1,380
40	PowerNet Limited	Routine and corrective maintenance and inspection	4,456
41	PowerNet Limited	Asset replacement and renewal (opex)	642
42	PowerNet Limited	System operations and network support	2,249
43	PowerNet Limited	Business support	3,045
44	PowerNet Limited	Consumer connection	13,101
45	PowerNet Limited	System growth	3,278
46	PowerNet Limited	Asset replacement and renewal (capex)	11,263
47	PowerNet Limited	Asset relocations	285
48	PowerNet Limited	Quality of supply	576
49	PowerNet Limited	Other reliability, safety and environment	3,735
50			
51			
52			
53	**Total value of related party transactions**		48,377
54	** include additional rows if needed*		
55			

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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
11	US Private Placement (USPP) US $40M	4/2/2020	7/11/2019	10.0	BKBM plus margin	62,794	57,216	235	(63)
12	US Private Placement (USPP) US $25M	4/2/2020	7/11/2019	11.0	BKBM plus margin	39,246	35,760	177	(43)
13	US Private Placement (USPP) NZ $50M	20/5/2021	19/3/2021	12.0	3.80%	50,000	50,000	263	(58)
14									
15									
16	** include additional rows if needed*						142,976	675	(164)

17
18 ### 5c(ii): Attribution of Term Credit Spread Differential
19

sch ref			
20	**Gross term credit spread differential**		511
21			
22	Total book value of interest bearing debt	236,154	
23	Leverage	42%	
24	Average opening and closing RAB values	474,373	
25	**Attribution Rate (%)**		84%
26			
27	**Term credit spread differential allowance**		431

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For Year Ended	31 March 2023

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

7 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)			
9						
10	**Service interruptions and emergencies**					
11	Directly attributable		4,367			
12	Not directly attributable				–	
13	**Total attributable to regulated service**		4,367			
14	**Vegetation management**					
15	Directly attributable		1,380			
16	Not directly attributable				–	
17	**Total attributable to regulated service**		1,380			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		4,456			
20	Not directly attributable				–	
21	**Total attributable to regulated service**		4,456			
22	**Asset replacement and renewal**					
23	Directly attributable		642			
24	Not directly attributable				–	
25	**Total attributable to regulated service**		642			
26	**System operations and network support**					
27	Directly attributable		2,986			
28	Not directly attributable				–	
29	**Total attributable to regulated service**		2,986			
30	**Business support**					
31	Directly attributable		3,295			
32	Not directly attributable		739	40	779	
33	**Total attributable to regulated service**		4,034			
34						
35	**Operating costs directly attributable**		17,126			
36	**Operating costs not directly attributable**	–	739	40	779	–
37	**Operational expenditure**		17,864			
38						

39 5d(ii): Other Cost Allocations

sch ref		($000)
40	**Pass through and recoverable costs**	
41	**Pass through costs**	
42	Directly attributable	571
43	Not directly attributable	–
44	**Total attributable to regulated service**	571
45	**Recoverable costs**	
46	Directly attributable	12,858
47	Not directly attributable	
48	**Total attributable to regulated service**	12,858
49		

50 5d(iii): Changes in Cost Allocations* †

sch ref				($000) CY-1	Current Year (CY)
51					
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	–	–
56					
57	Rationale for change				
58					
59					
60					
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	–	–
65					
66	Rationale for change				
67					
68					
69					
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	–	–
74					
75	Rationale for change				
76					
77					

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	The Power Company Limited
For Year Ended	31 March 2023

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref		
7	**5e(i): Regulated Service Asset Values**	
8		**Value allocated ($000s)**
9		**Electricity distribution services**
10	**Subtransmission lines**	
11	Directly attributable	66,724
12	Not directly attributable	–
13	**Total attributable to regulated service**	66,724
14	**Subtransmission cables**	
15	Directly attributable	5,548
16	Not directly attributable	–
17	**Total attributable to regulated service**	5,548
18	**Zone substations**	
19	Directly attributable	126,181
20	Not directly attributable	–
21	**Total attributable to regulated service**	126,181
22	**Distribution and LV lines**	
23	Directly attributable	168,298
24	Not directly attributable	–
25	**Total attributable to regulated service**	168,298
26	**Distribution and LV cables**	
27	Directly attributable	22,230
28	Not directly attributable	–
29	**Total attributable to regulated service**	22,230
30	**Distribution substations and transformers**	
31	Directly attributable	62,461
32	Not directly attributable	–
33	**Total attributable to regulated service**	62,461
34	**Distribution switchgear**	
35	Directly attributable	31,044
36	Not directly attributable	–
37	**Total attributable to regulated service**	31,044
38	**Other network assets**	
39	Directly attributable	8,887
40	Not directly attributable	–
41	**Total attributable to regulated service**	8,887
42	**Non-network assets**	
43	Directly attributable	–
44	Not directly attributable	–
45	**Total attributable to regulated service**	–
46		
47	**Regulated service asset value directly attributable**	491,373
48	**Regulated service asset value not directly attributable**	–
49	**Total closing RAB value**	491,373
50		

sch ref					
51	**5e(ii): Changes in Asset Allocations* †**				
52					**($000)**
53	**Change in asset value allocation 1**			**CY-1**	**Current Year (CY)**
54	Asset category		Original allocation		
55	Original allocator or line items		New allocation		
56	New allocator or line items		Difference	–	–
57					
58	Rationale for change				
59					
60					
61					**($000)**
62	**Change in asset value allocation 2**			**CY-1**	**Current Year (CY)**
63	Asset category		Original allocation		
64	Original allocator or line items		New allocation		
65	New allocator or line items		Difference	–	–
66					
67	Rationale for change				
68					
69					
70					**($000)**
71	**Change in asset value allocation 3**			**CY-1**	**Current Year (CY)**
72	Asset category		Original allocation		
73	Original allocator or line items		New allocation		
74	New allocator or line items		Difference	–	–
75					
76	Rationale for change				
77					
78					

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

Company Name **The Power Company Limited**
For Year Ended **31 March 2023**

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

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

sch ref					Allocator Metric (%)		Value allocated ($000)				
	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000)
11	**Service interruptions and emergencies**										
12										-	
13										-	
14										-	
15										-	
16	**Not directly attributable**						-	-	-	-	-
17	**Vegetation management**										
18										-	
19										-	
20										-	
21										-	
22	**Not directly attributable**						-	-	-	-	-
23	**Routine and corrective maintenance and inspection**										
24										-	
25										-	
26										-	
27										-	
28	**Not directly attributable**						-	-	-	-	-
29	**Asset replacement and renewal**										
30										-	
31										-	
32										-	
33										-	
34	**Not directly attributable**						-	-	-	-	-
35											
36	**System operations and network support**										
37										-	
38										-	
39										-	
40										-	
41	**Not directly attributable**						-	-	-	-	-
42	**Business support**										
43	Administration expenses	ABAA	Revenue	Proxy	94.85%	5.15%		739	40	779	
44										-	
45										-	
46										-	
47	**Not directly attributable**						-	739	40	779	-
48											
49	**Operating costs not directly attributable**						-	739	40	779	-
50											
51	**Pass through and recoverable costs**										
52	**Pass through costs**										
53										-	
54										-	
55										-	
56										-	
57	**Not directly attributable**						-	-	-	-	-
58	**Recoverable costs**										
59										-	
60										-	
61										-	
62										-	
63	**Not directly attributable**						-	-	-	-	-
64	** include additional rows if needed*										

Company Name: **The Power Company Limited**
For Year Ended: **31 March 2023**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

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

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

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2023**

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

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

sch ref				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		13,101
9		System growth		3,278
10		Asset replacement and renewal		11,263
11		Asset relocations		285
12		Reliability, safety and environment:		
13		Quality of supply	576	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	3,735	
16		**Total reliability, safety and environment**		4,311
17		**Expenditure on network assets**		32,239
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		32,239
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		9,778
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		22,462
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		Half Hour Individuals	10,815	
33		Non- Domestic	616	
34		Domestic	1,670	
35				
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		13,101
39				
40	*less*	Capital contributions funding consumer connection expenditure	8,783	
41		**Consumer connection less capital contributions**		4,318
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement**
43			**System Growth**	**and Renewal**
44			**($000)**	**($000)**
45		Subtransmission	30	99
46		Zone substations	–	2,053
47		Distribution and LV lines	1,122	5,505
48		Distribution and LV cables	1,507	52
49		Distribution substations and transformers	400	1,731
50		Distribution switchgear	218	1,743
51		Other network assets	1	80
52		**System growth and asset replacement and renewal expenditure**	3,278	11,263
53	*less*	Capital contributions funding system growth and asset replacement and renewal	829	3
54		**System growth and asset replacement and renewal less capital contributions**	2,449	11,260
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Line relocation	285	
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations		
65		**Asset relocations expenditure**		285
66	*less*	Capital contributions funding asset relocations	161	
67		**Asset relocations less capital contributions**		124

pwc

6a(vi): Quality of Supply

		($000)	($000)
	*Project or programme**		
	Supply Quality Upgrades	218	
	Network Improvements Projects	173	
	Mobile Substation Site Made Ready	185	
	** include additional rows if needed*		
	All other projects programmes - quality of supply		
	Quality of supply expenditure		576
less	Capital contributions funding quality of supply		
	Quality of supply less capital contributions		576

6a(vii): Legislative and Regulatory

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

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

		($000)	($000)
	*Project or programme**		
	Earth Upgrades	2,416	
	Substation Safety	379	
	Comms Projects	217	
	Kennington Fibre install	194	
	** include additional rows if needed*		
	All other projects or programmes - other reliability, safety and environment	529	
	Other reliability, safety and environment expenditure		3,735
less	Capital contributions funding other reliability, safety and environment		
	Other reliability, safety and environment less capital contributions		3,735

6a(ix): Non-Network Assets

Routine expenditure

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

Atypical expenditure

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

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2023**

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	4,367	
9	Vegetation management	1,380	
10	Routine and corrective maintenance and inspection	4,456	
11	Asset replacement and renewal	642	
12	**Network opex**		10,845
13	System operations and network support	2,986	
14	Business support	4,033	
15	**Non-network opex**		7,019
16			
17	**Operational expenditure**		17,864
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	*EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*		
20	Energy efficiency and demand side management, reduction of energy losses		63
21	Direct billing*		–
22	Research and development		–
23	Insurance		425
24	Cybersecurity (Commission only)		–
25	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	The Power Company Limited
For Year Ended	31 March 2023

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

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

sch ref

sch ref		Target ($000) [1]	Actual ($000)	% variance
7	**7(i): Revenue**			
8	Line charge revenue	60,942	59,970	(2%)
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	13,045	13,101	0%
11	System growth	3,330	3,278	(2%)
12	Asset replacement and renewal	12,403	11,263	(9%)
13	Asset relocations	123	285	132%
14	Reliability, safety and environment:			
15	Quality of supply	418	576	38%
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	4,996	3,735	(25%)
18	**Total reliability, safety and environment**	5,415	4,311	(20%)
19	**Expenditure on network assets**	34,315	32,239	(6%)
20	Expenditure on non-network assets	131	–	(100%)
21	Expenditure on assets	34,446	32,239	(6%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	3,825	4,367	14%
24	Vegetation management	1,150	1,380	20%
25	Routine and corrective maintenance and inspection	4,208	4,456	6%
26	Asset replacement and renewal	842	642	(24%)
27	**Network opex**	10,025	10,845	8%
28	System operations and network support	2,916	2,986	2%
29	Business support	3,997	4,033	1%
30	**Non-network opex**	6,913	7,019	2%
31	**Operational expenditure**	16,938	17,864	5%
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	–	63	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	424	425	0%
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 **The Power Company Limited**
For Year Ended **31 March 2023**
Network / Sub-Network Name

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8 **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)	Billed quantities by price component					
12					Price component	Variable day energy sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases		
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	kWh	kWh	kWh		
15	Low user	Residential	Standard	10,088	59,780		27,031,398	22,966,782	16,651,191		
16	Domestic	Residential	Standard	17,657	160,156		66,970,266	57,559,020	43,459,404		
17	Non-Domestic	Commerical	Standard	9,309	211,139		90,241,598	77,304,770	57,706,171		
18	Individual non half hour	Commerical	Standard	57	8,797		3,760,067	3,221,032	2,404,424		
19	Individual half hour	Commerical	Standard	210	206,859	125,029,862					
20	Non-Standard	Commerical	Non-standard	4	175,318	136,079,650					
21	Generation	Commerical	Non-standard	2	448	326,631					
22											
23											
24											
25	*Add extra rows for additional consumer groups or price category codes as necessary*										
26			Standard consumer totals	37,321	646,733	125,029,862	188,003,328	161,051,604	120,221,189	–	–
27			Non-standard consumer totals	6	175,765	136,406,281	–	–	–	–	–
28			Total for all consumers	37,327	822,498	261,436,143	188,003,328	161,051,604	120,221,189	–	–

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

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2023**
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

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

							Line charge revenues ($000) by price component						
							Price component	Fixed	Variable Day energy Sales	Variable Peak energy purchases	Variable Shoulder energy purchases	Variable Night energy purchases	
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)**	**Rate (eg, $ per day, $ per kWh, etc.)**	$/Day	$/kWh	$/kWh	$/kWh	$/kWh	
Low user	Residential	Standard	$6,923	$1,041	$5,876	$1,047		$834	–	$3,577	$2,605	($94)	
Domestic	Residential	Standard	$18,479	$2,650	$15,712	$2,766		$9,631	–	$5,200	$3,894	($247)	
Non-Domestic	Commerical	Standard	$22,476	$3,325	$19,069	$3,407		$9,095	–	$7,617	$5,729	$35	
Individual non half hour	Commerical	Standard	$587	$69	$429	$158		$11	–	$324	$245	$6	
Individual half hour	Commerical	Standard	$5,599	$544	$2,501	$3,098		$3,203	$2,396	–	–	–	
Non-Standard	Commerical	Non-standard	$4,456	$289	$2,255	$2,201		$4,456	–	–	–	–	
Generation	Commerical	Non-standard	$1,451	$45	$1,270	$180		$1,451	–	–	–	–	
			–										
			–										
			–										
Add extra rows for additional consumer groups or price category codes as necessary													
		Standard consumer totals	$54,063	$7,629	$43,587	$10,476		$22,773	$2,396	$16,719	$12,474	($299)	–
		Non-standard consumer totals	$5,907	$334	$3,525	$2,382		$5,907	–	–	–	–	–
		Total for all consumers	$59,970	$7,963	$47,112	$12,858		$28,680	$2,396	$16,719	$12,474	($299)	–

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

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	6	**Check**	**OK**

Company Name	The Power Company Limited
For Year Ended	31 March 2023
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
8								
9	All	Overhead Line	Concrete poles / steel structure	No.	92,494	92,995	501	3
10	All	Overhead Line	Wood poles	No.	17,485	17,103	(382)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	891	897	5	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	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	1	1	(0)	4
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.	58	58	–	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	59	59	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	13	13	–	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	302	295	(7)	3
29	HV	Zone substation switchgear	33kV RMU	No.	2	2	–	4
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	23	23	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	34	35	1	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	158	157	(1)	3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	48	47	(1)	3
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	61	61	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	6,719	6,723	4	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	9	9	(0)	3
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	121	122	1	3
39	HV	Distribution Cable	Distribution UG PILC	km	34	36	2	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	27	28	1	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	28	34	6	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	13,796	13,133	(663)	3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	N/A
45	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	114	116	2	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	10,635	10,681	46	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	705	725	20	3
48	HV	Distribution Transformer	Voltage regulators	No.	72	76	4	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	7	7	–	3
50	LV	LV Line	LV OH Conductor	km	849	849	1	3
51	LV	LV Cable	LV UG Cable	km	224	232	8	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	359	363	4	3
53	LV	Connections	OH/UG consumer service connections	No.	38,735	38,968	233	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	665	703	38	3
55	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	1	1	–	4
56	All	Capacitor Banks	Capacitors including controls	No	6	6	–	4
57	All	Load Control	Centralised plant	Lot	5	5	–	4
58	All	Load Control	Relays	No	–	–	–	N/A
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name **The Power Company Limited**
For Year Ended **31 March 2023**
Network / Sub-network Name

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 **Disclosure Year (year ended)**

sch ref	Voltage	Asset category	Asset class	Units	Number of assets at disclosure year end by installation date																																No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
9					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				
10	All	Overhead Line	Concrete poles / steel structure	No.	–	–	2,187	35,890	11,863	20,780	2,971	202	837	1,018	615	175	88	137	328	318	901	1,214	795	931	1,019	1,202	1,215	1,343	1,557	1,244	1,211	781	850	670	72	–	–	581	92,995		3
11	All	Overhead Line	Wood poles	No.	–	–	434	1,163	3,897	578	3,429	729	754	721	730	706	453	859	781	1,033	114	6	2	16	13	164	2	18	12	17	3	10	–	6	3	–	–	450	17,103		3
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	129	125	126	139	137	59	35	8	26	–	–	0	26	22	1	–	0	–	–	36	13	–	12	1	–	0	–	0	–	–	–	2	897		3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	–	1	–	0	1	0	0	1	–	2	0	–	–	–	–	–	–	2	–	0	–	0	4	0	0	–	–	–	1	13		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	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	1		4
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	7	10	6	6	–	2	1	–	–	–	–	1	–	–	–	–	1	1	1	1	1	8	3	3	–	–	–	–	–	–	4	58		4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	11	6	1	–	–	2	2	2	13	–	5	–	–	3	2	1	–	–	5	4	–	–	2	–	–	–	–	–	59		4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	8	–	–	–	1	–	–	4	–	–	–	–	13		4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	18	11	10	25	63	3	35	2	1	9	7	10	23	2	7	1	1	8	4	5	5	–	5	7	10	6	2	3	4	–	–	8	295		3
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	2		4
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	7	–	–	–	5	–	–	–	–	–	–	–	–	7	1	–	–	–	1	–	2	–	–	–	–	23		4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	1	1	3	6	–	–	–	–	–	1	2	3	2	–	1	1	–	–	–	–	–	2	–	1	4	3	2	2	–	–	–	35		3
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	14	48	–	–	1	–	–	–	–	6	–	2	–	–	17	10	13	14	9	6	7	5	4	1	–	–	–	–	–	157		3
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	3	18	6	–	–	1	3	1	–	–	1	–	1	–	–	4	1	–	–	2	1	–	2	3	–	–	–	–	–	47		3
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	6	8	8	2	1	3	2	1	3	–	2	–	2	1	–	–	1	8	1	2	2	4	2	–	1	–	–	1	–	–	–	61		4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3	0	188	715	3,235	1,060	305	47	97	102	68	59	55	54	72	102	76	49	50	55	38	75	34	34	12	21	20	16	18	35	0	–	–	28	6,723		3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
38	HV	Distribution Line	SWER conductor	km	–	–	–	4	1	–	–	–	–	–	–	–	–	–	–	4	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	9		3
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	0	15	6	5	2	4	3	5	9	4	5	8	4	3	2	1	5	1	4	6	3	1	15	1	3	1	0	0	–	–	8	122		3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	0	13	3	8	1	–	1	0	–	3	1	3	1	0	0	1	0	–	0	–	–	0	–	–	–	–	–	–	–	–	2	36		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.	–	–	–	–	–	1	3	–	–	–	–	1	2	1	–	–	1	–	–	–	2	3	–	4	2	4	3	–	–	1	–	–	–	–	28		3
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	1	–	2	6	14	2	7	–	–	–	–	–	34		3
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	–	1	171	282	1,195	1,894	1,361	105	317	385	268	290	238	322	379	427	438	410	372	350	305	366	288	217	250	278	296	307	326	331	71	–	–	893	13,133		3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	1	2	8	–	–	–	6	–	3	3	7	10	7	2	1	3	1	2	3	–	4	23	5	15	7	3	–	–	–	–	116		3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	–	1	150	65	1,161	1,779	1,304	96	303	370	249	239	224	308	364	396	398	372	332	316	249	317	241	173	204	183	194	200	204	227	50	–	–	12	10,681		3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	3	6	77	80	37	5	19	24	20	31	25	33	33	27	24	21	13	16	21	29	17	17	34	21	18	22	18	26	7	–	–	1	725		3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	4	–	1	6	5	5	16	13	3	–	–	–	–	8	–	–	4	–	1	1	–	9	–	–	–	–	76		3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	4	–	1	–	–	–	–	–	–	–	1	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7		3
51	LV	LV Line	LV OH Conductor	km	–	–	18	71	480	103	42	3	9	11	7	5	4	6	6	7	6	5	4	4	5	5	4	5	6	5	8	5	4	4	1	–	–	8	849		3
52	LV	LV Cable	LV UG Cable	km	–	–	0	2	80	20	11	1	1	4	4	7	13	14	15	6	7	5	4	3	3	2	3	1	3	4	4	2	4	2	0	–	–	6	232		3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	14	236	41	17	1	3	2	1	3	4	3	2	1	1	3	2	1	2	0	0	0	2	2	1	4	1	1	–	–	–	13	363		3
54	LV	Connections	OH/UG consumer service connections	No.	–	202	2,107	5,231	6,978	7,819	6,897	242	341	429	429	412	460	507	563	681	518	419	473	358	398	329	300	282	338	338	406	410	433	441	93	–	–	134	38,968		3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	8	9	41	92	17	11	1	3	4	19	8	26	18	8	5	4	30	15	25	37	35	51	44	38	60	38	33	12	–	–	11	703		3
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	Lot	–	–	–	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1		4
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6		4
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	2	3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5		4
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–		N/A

Company Name	The Power Company Limited
For Year Ended	31 March 2023
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	531	–	531
13	33kV	366	14	380
14	SWER (all SWER voltages)	5	4	9
15	22kV (other than SWER)	0	1	1
16	6.6kV to 11kV (inclusive—other than SWER)	6,723	158	6,881
17	Low voltage (< 1kV)	849	232	1,082
18	**Total circuit length (for supply)**	8,474	408	8,882
19				
20	Dedicated street lighting circuit length (km)	271	92	363
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	475	6%	
25	Rural	4,552	54%	
26	Remote only	805	9%	
27	Rugged only	2,029	24%	
28	Remote and rugged	614	7%	
29	Unallocated overhead lines	0	0%	
30	**Total overhead length**	8,474	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,542	17%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	1,573	19%	

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2023**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

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

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

Company Name	The Power Company Limited
For Year Ended	31 March 2023
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref			
8	**9e(i): Consumer Connections and Decommissionings**		
9	*Number of ICPs connected during year by consumer type*		
10	*Consumer types defined by EDB**	**Number of connections (ICPs)**	
11	Domestic	334	
12	Non Domestic	74	
13	Half Hour Individual	5	
14			
15			
16	** include additional rows if needed*		
17	**Connections total**	413	
18			
19	*Number of ICPs decommissioned during year by consumer type*		
20	*Consumer types defined by EDB**	**Number of decommissionings**	
21	Domestic	41	
22	Non Domestic	47	
23	Individual non half hour	1	
24	Half Hour Individual	1	
25			
26	** include additional rows if needed*		
27	**Decommissionings total**	90	
28			
29	**Distributed generation**		
30	Number of connections made in year	48	**connections**
32	Capacity of distributed generation installed in year	0.28	**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	148	
39	*plus* Distributed generation output at HV and above	13	
40	**Maximum coincident system demand**	161	
41	*less* Net transfers to (from) other EDBs at HV and above	1	
42	**Demand on system for supply to consumers' connection points**	160	
43	**Electricity volumes carried**	**Energy (GWh)**	
44	Electricity supplied from GXPs	743	
45	*less* Electricity exports to GXPs	92	
46	*plus* Electricity supplied from distributed generation	226	
47	*less* Net electricity supplied to (from) other EDBs	13	
48	**Electricity entering system for supply to consumers' connection points**	865	
49	*less* Total energy delivered to ICPs	822	
51	**Electricity losses (loss ratio)**	42	4.9%
52			
53	**Load factor**	0.62	
54	**9e(iii): Transformer Capacity**		
55		**(MVA)**	
56	Distribution transformer capacity (EDB owned)	478	
57	Distribution transformer capacity (Non-EDB owned, estimated)	24	
58	**Total distribution transformer capacity**	501	
59			
60	**Zone substation transformer capacity**	468	
61			

Company Name	The Power Company Limited
For Year Ended	31 March 2023
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

10(i): Interruptions

Interruptions by class	Number of interruptions
Class A (planned interruptions by Transpower)	–
Class B (planned interruptions on the network)	483
Class C (unplanned interruptions on the network)	1,347
Class D (unplanned interruptions by Transpower)	–
Class E (unplanned interruptions of EDB owned generation)	–
Class F (unplanned interruptions of generation owned by others)	–
Class G (unplanned interruptions caused by another disclosing entity)	1
Class H (planned interruptions caused by another disclosing entity)	–
Class I (interruptions caused by parties not included above)	–
Total	1,831

Interruption restoration	≤3Hrs	>3hrs
Class C interruptions restored within	943	404

SAIFI and SAIDI by class	SAIFI	SAIDI
Class A (planned interruptions by Transpower)	–	–
Class B (planned interruptions on the network)	0.6427	147.74
Class C (unplanned interruptions on the network)	3.7707	348.66
Class D (unplanned interruptions by Transpower)	–	–
Class E (unplanned interruptions of EDB owned generation)	–	–
Class F (unplanned interruptions of generation owned by others)	–	–
Class G (unplanned interruptions caused by another disclosing entity)	0.0003	0.03
Class H (planned interruptions caused by another disclosing entity)	–	–
Class I (interruptions caused by parties not included above)	–	–
Total	4.4137	496.43

Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
Classes B & C (interruptions on the network)	4.4134	403.39

Transitional SAIDI and SAIDI (previous method)

*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	0.0783	8.57
Vegetation	0.3620	53.28
Adverse weather	0.8130	115.10
Adverse environment	–	–
Third party interference	0.5303	41.36
Wildlife	0.0971	7.10
Human error	0.1094	3.63
Defective equipment	1.1665	86.22
Cause unknown	0.6141	33.40

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	0.0190	5.23
Subtransmission cables	–	–
Subtransmission other	–	–
Distribution lines (excluding LV)	0.5702	130.53
Distribution cables (excluding LV)	0.0093	0.92
Distribution other (excluding LV)	0.0442	11.06

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

Main equipment involved	SAIFI	SAIDI
Subtransmission lines	0.6056	67.83
Subtransmission cables	0.0000	0.17
Subtransmission other	0.1335	2.18
Distribution lines (excluding LV)	2.6412	256.08
Distribution cables (excluding LV)	0.0214	0.96
Distribution other (excluding LV)	0.3690	21.44

10(v): Fault Rate

Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
Subtransmission lines	20	897	2.23
Subtransmission cables	1	14	7.29
Subtransmission other	3		
Distribution lines (excluding LV)	1,045	6,728	15.53
Distribution cables (excluding LV)	6	162	3.70
Distribution other (excluding LV)	272		
Total	1,347		

SCHEDULE 14 MANDATORY EXPLANATORY NOTES

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

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

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

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

Return on Investment (Schedule 2)

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

Box 1: Explanatory comment on return on investment

The Power Company Limited achieved a post-tax ROI of 8.15%, which is 2.59% above the 75th percentile estimate of post-tax WACC of 5.56%. The Power Company also achieved an 8.66% vanilla ROI, which is 2.59% above the 75th percentile estimate of vanilla WACC of 6.07%.

No items were reclassified in the disclosure year.

Regulatory Profit (Schedule 3)

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

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

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

Box 2: Explanatory comment on regulatory profit

Included in other regulated income is income related to the Mobile Substation, the Seaward Bush to Bluff 33kv distribution lines, and insurance reimbursement for customer claims.

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) used the 31 March 2022 figure of $457,373k as the starting point with inflationary indexing over the year to 31 March 2023 plus additions less disposals, resulting in a closing RAB balance of $491,373k at 31 March 2023. 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 deductible expenditure not included in regulatory profit is the $95k 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 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)

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

Taxable Capital Contributions:	$	2,263
	$	2,263
Tax Rate:		28%
Temporary Differences	$	634

Cost allocation (Schedule 5d)

10. In the box below, comment on cost allocation as disclosed in Schedule 5d. This comment must include information on reclassified items in accordance with subclause 2.7.1(2).

Box 7: Cost allocation

With the exception of some Business Support costs (which have been apportioned using the ABAA method via a revenue proxy cost allocator), all other costs are 100% directly attributable to electricity distribution services.

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

No items were reclassified.

Asset allocation (Schedule 5e)

11. In the box below, comment on cost allocation as disclosed in Schedule 5e. This comment must include information on reclassified items in accordance with clause 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 2.7.1(2).

Box 9: Explanation of capital expenditure for the disclosure year
The materiality threshold of programmes or projects identified during the disclosure year was set at $500k. Lower value projects with defined scope were included in the list for specific identification within categories. No items were reclassified during the disclosure year.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

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

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

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

Box 10: Explanation of capital expenditure for the disclosure year
Reactive and minor maintenance is performed on The Power Company Limited's transformers and lines. When the work performed is not material in relation to the overall value of the asset, it is classified as routine and corrective maintenance and inspection. No items were reclassified during the disclosure year. There was no material atypical expenditure disclosed in Schedule 6b.

Variance between forecast and actual expenditure (Schedule 7)

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

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

Capital Expenditure:
The overall actual capex expenditure on network assets was 6% under budget.

System Growth
- 2% under budget
- Two planned line reinforcements were delayed beyond the financial year end due the loading requiring work to be completed in the dairy off season.

Asset replacement and renewal
- 9% under budget.
- Late delivery of switchgear and building material for the two-year Orawia substation upgrade.
- ABS replacement work did not achieve budget due to equipment delivery delays.
- LV pillar box replacements largely reactive inspection driven work with some supply issues.

Asset relocations:
- 132% over budget.
- Work mainly driven by customer request and Territorial Local Authority work program with the opportunity taken to move lines to the roadside where it is economical.

Quality of supply:
- 38% over budget.
- Additional work for mobile substation connection.
- Completion work on communications network improvement projects

Other Reliability, Safety and Environment:
- 25% under budget.
- Earth upgrades had a delayed start due to labour and plant constraints earlier in the year.
- Radio equipment delivery delays affected the completion of the communications project.

Operational Expenditure:
Total operational expenditure was 5% over budget.

Service interruptions and emergencies
- 14% over budget
- Higher unplanned distribution fault response costs due to faults from weather conditions and some increased material costs.

Vegetation management:
- 20% over budget
- New Asplundh contract rates and amount of work completed was higher than budgeted, with more trees being identified and cut.

Routine and corrective maintenance:
- 6% over budget.
- Corrective maintenance higher due to cable fault repairs and 66kV busing replacement.
- Distribution routine maintenance higher due to reactive maintenance requirements from the inspection program.
- Connections maintenance incurred an additional costs from smart meter data providers.

Asset replacement and renewal maintenance:
- 24% under budget
- Work is largely driven from the inspection program with less distribution refurbishment work identified during the year.

Information relating to revenues and quantities for the disclosure year

15. In the box below provide-

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

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

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

Target revenue for the year was $60,942k, the total billed was $59,970k which is $972k (2%) below budget.

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 13: Commentary on network reliability for the disclosure year

Due to its consumer ownership, The Power Company Ltd (TPCL) is not subject to Default Price-Quality Path (DPP) regulation. Nonetheless TPCL calculates SAIDI and SAIFI limits and targets for non-exempt networks to allow for assessment of performance on a consistent basis with other networks.

TPCL 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 TPCL has counted the successive interruptions within the initial interruption when calculating SAIFI in line with previous years.

TPCL has disclosed a normalised SAIDI at 403.39 and normalised SAIFI at 4.4134 for 2022/23. The regulatory year 2022/23 normalised SAIFI is 28% higher than the 2021/22 year, with normalised SAIDI 12% higher. TPCL published ID Determination values for normalised SAIDI of 360.9 and normalised SAIFI of 3.46 for the 2021/22 year – meaning more interruptions, and longer duration compared with last year.

The total number of power interruptions on TPCL is similar to 2021/22. There was a decrease of 9% in Class B planned interruptions, and 3% increase in Class C unplanned interruptions.

Class C SAIFI of 3.77 was the major contributor to overall SAIFI, with an increase of 44% to 2021/22. Class C SAIDI was 99% higher indicating longer times to restore supply for faults. Class B SAIDI and SAIFI was 23% lower than 2021/22.

The most significant cause of Class C interruptions was Adverse weather, which significantly increased in frequency and duration compared with last year. Defective equipment, Vegetation, Third party interference and Cause Unknown were also high contributors to Class C SAIDI. Defective equipment was the most significant cause of Class C interruptions, based on SAIFI.

86% of TPCL's network is distribution lines (excluding LV), accordingly 88% of planned interruptions and 73% of unplanned interruptions occurred on these lines, based on SAIDI.

Fault rates per 100km was similar for lines with distribution cables improving from 5.63 in 2021/22 to 3.70. Only one fault occurred this year on subtransmission cables giving a rate of 7.29 per 100km, no faults occurred last year on subtransmission cables.

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

The Power Company Limited insures its substations, network equipment and buildings.

- Substations and network equipment are insured for $188.89 million.

Lines and cables are not insured.

The Power Company Limited therefore "self-insures" but does not recognise the cost of self-insurance.

Amendments to previously disclosed information

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

    18.1 a description of each error; and

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

Box 15: Disclosure of amendment to previously disclosed information

No amendments were disclosed.

SCHEDULE 14A MANDATORY EXPLANATORY NOTES ON FORECAST INFORMATION

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

1. This Schedule provides for 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 report released in December 2021:

	2023	2024	2025	2026	2027
Inflator (CAPEX & OPEX)	1.4%	1.8%	2.1%	2.1%	5.1%

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

SCHEDULE 15 VOLUNTARY EXPLANATORY NOTES

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

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

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

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

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

Voluntary explanatory comment on disclosed information

Schedule 10

Due to its consumer ownership, The Power Company Ltd (TPCL) is not subject to Default Price-Quality Path (DPP) regulation. Nonetheless TPCL calculates SAIDI and SAIFI limits and targets for non-exempt networks to allow for assessment of performance on a consistent basis with other networks. Therefore, network reliability is compliant with quality requirements under DPP3, however due to the manual nature of the interruption reporting process, there are inherent limitations in the ability of TPCL 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 interruption statistics.

A number of 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 amendment of records from the outage system, and retention of documentation.

APPENDICES

A. Related Party Transaction Additional Information Disclosure

APPENDIX A:

Related Party Transactions:

Additional Information Disclosures

1. INTRODUCTION

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

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

- **The Power Company Limited's Information Disclosure**, for the year ended 31 March 2023 - Schedule 5(b) Related party Transactions

2. INFORMATION DISCLOSURE REQUIREMENTS

The Related Party Transaction information disclosed on the following pages has been prepared in accordance with **Full Disclosure** requirements, due to the level of expenditure incurred by a related party on the The Power Company Limited (TPCL) network assets, being greater than $20 million for the year ending 31 March 2023.

Full Disclosure requires additional information be provided associated with related party transactions, including related party relationships, procurement policies & processes, application of these policies & processes and examples of market testing of transaction terms. The IM Determination require all related party transactions be valued at an 'arm's length' basis. Under Full Disclosure, an independent appraiser is required to assess whether the related party transactions comply with an 'arm's length' valuation criteria at least every 3 years.

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

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 Power Company Limited has an interest in the PowerNet Limited Joint Venture, the OtagoNet Joint Venture, Lakeland Network Limited, and the Southern Generation Limited Partnership through their wholly owned subsidiary company Last Tango Limited.

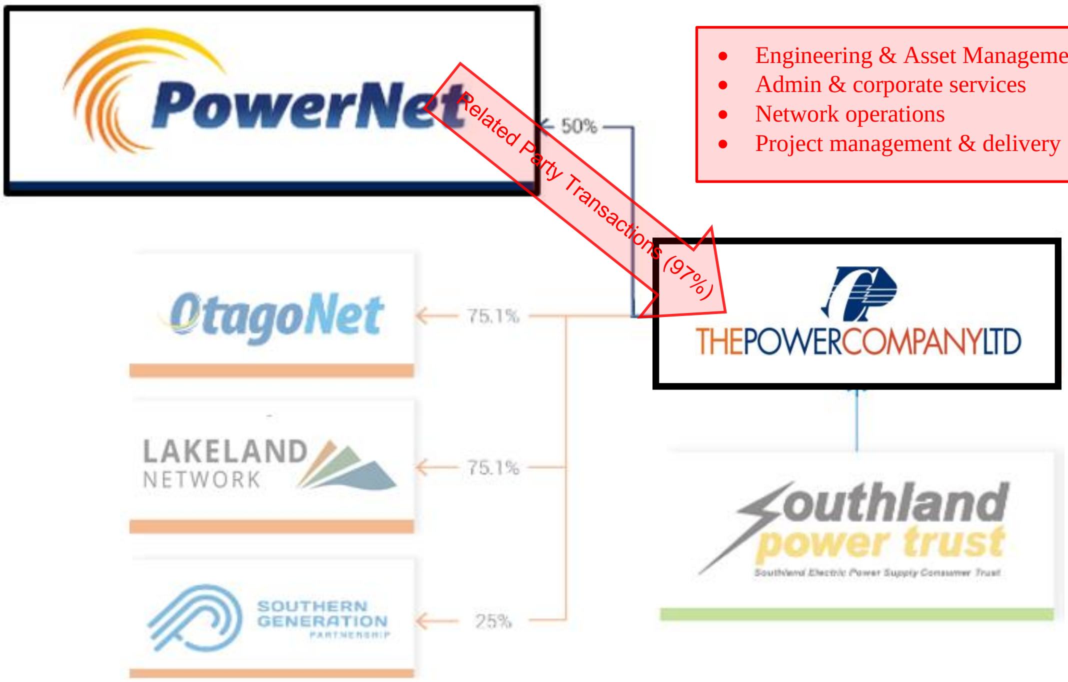
During the year ending 31 March 2023, TPCL had related party transactions with the following entities:

- Goods and services provided by – PowerNet Limited;
- Goods and services provided to – PowerNet Limited, OtagoNet Joint Venture.

Company Structure

The Power Company Limited (TPCL) is wholly-owned by the Southland Electric Power Supply Consumer Trust ("Southland Power Trust"). The following diagrams illustrate TPCL's ownership interests in PowerNet and other related entities, and the nature of related party transaction work undertaken.

ID Determination reference: 2.3.8



pwc

a. **PowerNet Limited**

TPCL holds a 50% shareholding in electricity network management company PowerNet Limited (PowerNet). PowerNet provides a range of field contracting, asset management, system control and business services to TPCL. The value of regulatory related goods and services provided to TPCL by PowerNet, for the year ended 31 March 2023, is categorised as follows:

		($000)
Operating Expenditure:		
i.	Service interruptions and emergencies	4,367
ii.	Vegetation management	1,380
iii.	Routine and corrective maintenance and inspection	4,456
iv.	Asset replacement and renewal (Opex)	642
v.	System operations and network support	2,249
vi.	Business support	3,045
Capital Expenditure:		
vii.	Consumer connection	13,101
viii.	System growth	3,278
ix.	Asset replacement and renewal (Capex)	11,263
x.	Asset relocations	285
xi.	Quality of supply	576
xii.	Other reliability, safety and environment	3,735
	Total PowerNet Related Party expenditure	**48,377**

In the year to 31 March 2023, PowerNet provided 100% of the TPCL Lines Business Capital Expenditure, and 90% 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 TPCL, in the form of an "agency agreement".

Services provided under the agreement include:

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

b. OtagoNet Joint Venture

TPCL has a 75.1% ownership interest in the OtagoNet Joint Venture electricity distribution network (OJV), based in coastal and inland Otago, via a joint venture arrangement with Electricity Invercargill Ltd.

During the year, TPCL received $60,000 from OJV relating to the rental of specialised substation equipment, otherwise there were no other related party transactions between OJV and TPCL during the reporting period.

Network Management Agreement

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

While TPCL owns the Network Assets and provides electricity distribution services through their network across Southland (excluding parts of Invercargill city and the Bluff township area), under the agreement PowerNet will manage the network assets, will carry out an agreed capital works programme, has the exclusive right to provide line function services, and will provide the business administration services on behalf of TPCL.

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 Electricity Invercargill Limited (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 acknowledged 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 a Network Management Fee to the EDB’s and metering businesses it manages under the NMA’s. These charges recover costs incurred in the performance of the system control services, asset management, corporate, finance and commercial services.

These network management 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 management fee charged to the EDB’s and metering businesses and
- the mark-up applied to capital expenditure 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), TPCL has 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 TPCL 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 TPCL, the PowerNet **Procurement Policy** (including the **Procurement Strategy**), is implied as also being the procurement practices followed by TPCL. Therefore, the Procurement Policy and Procurement Strategy provided for the purpose of this information disclosure, are as provided by PowerNet.

The PowerNet **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 TPCL are based on the PowerNet Procurement Policy and Strategy (FNPO-035). Under the NMA, PowerNet is responsible for sourcing all materials and services required to maintain the TPCL network assets and project manage the replacement or development of new assets, on behalf of TPCL. PowerNet recovers this expenditure through charging TPCL for capital and maintenance work, and through applying a management fee for recovering a share of the associated business services costs.

The **Procurement Policy** adopted by TPCL 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 party of TPCL for reporting purposes, the NMA is a commercial arrangement and is structured as two separate legal entities, with different ownership interests, operating on an 'arms-length' basis.

Planning
Adequate planning is an important part of the TPCL procurement process. Each year the PowerNet Network Asset Engineers prepare the TPCL Asset Management Plan (AMP) a strategic, long-term view of the Network capabilities and constraints. The AMP provides an internal asset management framework for TPCL's network, including the Annual Works Programme (AWP), detailing the capital and operating expenditure (asset maintenance, replacement and/or development) required. The AMP is reviewed and approved by the TPCL 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 TPCL 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, 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 negotiate more favourable competitive prices for goods and services, through the greater purchasing volumes and activity, than would otherwise be possible by TPCL alone. A supplier agreement with Corys Electrical makes it possible to source the required specialised electrical materials at near wholesale 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 is very small, and in some cases for specialised tasks, non-existent. PowerNet has learnt 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 TPCL'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. In many cases, external contractors are still required for large projects or technically challenging tasks, where resources can be outsourced (eg. approximately 19% of the TPCL Capital project expenditure during the 2022/23 year is non-PowerNet labour cost). 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 TPCL network meet outage performance targets (SAIDI & SAIFI targets). For this reason, in many cases for TPCL network asset maintenance tasks, the work is allocated to PowerNet internal labour teams with the appropriate skills and equipment.

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 competitively low prices in accordance with conditions in the PowerNet supply agreement.

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) and 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 TPCL's network assets are charged to TPCL 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 TPCL a management 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 TPCL customers are required to use PowerNet (Related Party) in relation to electricity distribution services are:

Fault Response and Reactive Maintenance

Under the Network Management Agreement, PowerNet is responsible for maintaining the TPCL 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 TPCL.

When a customer reports an outage, the PowerNet System Control operator will notify PowerNet staff to respond, (if they haven't done so already if an alarm system has been activated).

PowerNet provides on-call line mechanics and technicians, located across the Southland 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 TPCL network customers. Without these remote depot locations the duration (SAIDI) of outages on the TPCL 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 provides fault response services internally, rather than outsourcing.

New Connections

The process for requesting a new connection or capacity upgrade on the TPCL 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 TPCL 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 TPCL, 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 before PowerNet will begin any 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 Southland, 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/individual-connection/

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 TPCL network, in accordance with the Network Management Agreement. Due to the large, mainly rural, area of the TPCL network, PowerNet has a supplier agreement with network approved external contractors, to undertake the trimming and cutting of trees and vegetation where required. Arborist crews inspect the network lines and identify areas of risk where trees are growing inside the legal 'growth limit zone'. In these circumstances, the property owner is notified of their obligations by issuing a 'Tree Cut/Trim Notice'. Under the Tree regulations and TPCL's tree management process – the first cut or trim is at the cost of TPCL (via PowerNet managed external contractor). Following the first cut, the tree owner is responsible for keeping the tree(s) clear of the 'Growth Limit Zone' around TPCL's 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 TPCL network for the owner – making it clear owners are not obliged to use PowerNet's services.

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. If PowerNet is selected to do this work in TPCL's network area, instructions are provided to the respective sub-contractors to undertake the required work.

7. PROCUREMENT REPRESENTATIVE EXAMPLES

ID Determination 2.3.12 (3)

TPCL requires 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 suit the work being undertaken. The following list illustrates the categories of transactions with different procurement processes:

i. Major Construction Projects (System Growth/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 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 by PowerNet.

EXAMPLE: Athol to Kingston 11-22kV Upgrade Project

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Major Project' to upgrade aging assets.

Project Name:	Athol to Kingston 11-22kV Upgrade Project
Project Date:	June 2020 – March 2023
Project Number:	10757
Project Expenditure:	$ 715,514 External labour & materials $ 281,190 PowerNet services ---------------- $ 996,704 2022/23 Project Expenditure $ 793,567 2021/22 Project Expenditure $ 1,070,859 2020/21 Project Expenditure ---------------- $ 2,861,130 (Total Project Expenditure)
Project Classification:	System Growth (Capital)
Project Manager:	PowerNet Limited
Subcontractors:	PowerNet Ltd / Decom Ltd

An increase in electricity consumption is expected in the Kingston Area with a new housing development, sewage and water treatment station and several farms installing irrigation north of Garston. It was identified the feeder line from Athol to Kingston required upgrading to manage the future capacity increase. The project is split into geographical stages and is expected to take several years to complete. The 2022/23 project activity included the construction of a 66kV line from the Allendale regulator site to the proposed Kingston Substation site.

A review of available resources highlighted due to the size and technical challenges with this project, and in the interest of a timely construction, it was decided to outsource the majority of the construction to external suppliers.
PowerNet distribution teams from Gore and Lumsden undertook the linework.

Market Testing: The majority of the project expenditure related to outsourced activities to to external providers and materials provided through the Corys supply agreement. The PowerNet project management and internal labour cost is benchmarked to local market rates.

ii. New Connection / Capacity Upgrade (System Growth/Consumer Connections)

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.

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: New Subdivision Connection (December 2022)

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

Project Name:	New Subdivision Connection (TPCL Works programme)
Completion Date:	December 2022
Project Number:	CC 409943 / 397665
Project Expenditure:	$ 15,428 External materials & services $ 7,506 PowerNet services ------------ $ 22,934 Total Cost (2022/23)
Project Classification:	System Growth (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	Traffic Management, McDonough Contracting (trenching)

A customer installation connection application was received for Project CC409943 by PowerNet in March 2022. The customer requested an electricity connection to a new subdivision on their land in rural Southland, including the installation of a 50kVA transformer. The PowerNet distribution team undertook the work, being able to provide the skilled distribution services and equipment required. Materials were sourced through the Corys Supply Agreement.

Market Testing: PowerNet benchmarked internal labour rates favourably against similar Line Mechanic or Technician roles from other available external suppliers over the 2021-2023 period. Of the $13.1M capital expenditure spent on New Connections and Capacity Upgrades, 67% 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 Capital 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 TPCL 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: ABS Replacement (Southland – June 2022)

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

Project Name:	Remedy issues ANGLE RD E ABS (Defect 11342)
Completion Date:	June 2022
Project Number:	CC 397557
Project Expenditure:	\$ 7,804 External labour & materials \$ 7,753 PowerNet services -------------- \$ 15,557 Total Cost (2022/23)
Regulatory Classification:	Replacement & Renewal (Capital Expenditure)
Project Manager:	PowerNet – Carol Lowe
Construction:	PowerNet – Distribution
Subcontractors:	Traffic Management Services

PowerNet undertook Project CC397557 to replace an Air Break Switch on an 11kV Feeder near Woodlands following a routine inspection that identified a defect that could trigger asset failure and replacement was deemed essential to maintain security of supply within the area. The ABS was subsequently replaced in a planned process. 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 affected TPCL 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. Minimising power outage time of network faults, and minimising the number of customers impacted, is an important performance measure of TPCL network. As noted above, PowerNet Line Mechanics and Technicians provide an on-call service, able to respond quickly to an unplanned outage or event. PowerNet Line Mechanic 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.

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 2021-2023.

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

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

EXAMPLE: Vegetation Management (Rural Southland – January 2023)

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

Project Name:	Vegetation Control (TPCL Works Programme)
Project Completion Date:	January 2023
Project Number:	CC 436557
Project Number:	$ 2,255 External labour & materials $ 451 PowerNet services ---------- $ 2,706 (2022/23)
Regulatory Classification:	Vegetation Management (Operating Expenditure)
Project Manager:	PowerNet Ltd
Subcontractors:	Asplundh Ltd

PowerNet became aware of trees growing within the permissible distance of power lines during a routine Lines inspection in the rural Southland area. Details of the location and work required (‘tree clusters require trimming to comply with the Electricity (Hazard from Trees) Regulation 2003’) were noted on the PowerNet Cut/Trim Notice (CTN-2157), and provided to a network approved external contractor to provide a quote. PowerNet allocates this work based on capability and availability between the two network approved external contractors in Southland.

As this example was a ‘first cut’ notification, the cost of the work is charged to TPCL, rather than the property owner.

Market Testing: While PowerNet manages vegetation control work across TPCL network, almost all work is outsourced to external contractors, under a preferred supplier agreement, with set prices for different components of work undertaken. These prices are reviewed and agreed periodically by PowerNet, however, and are benchmarked where possible.

vi. Asset Maintenance (Routine and Corrective Maintenance)

Routine inspections and planned maintenance are important for maximising the useful life of TPCL network assets and equipment. PowerNet Network Asset Engineers undertake annual inspection work to identify assets that require maintenance.

EXAMPLE: Circuit Breaker Maintenance

The following example is provided to illustrate the procurement process followed by PowerNet (Related Party) for a 'Technical' planned maintenance project for the TPCL network:

Project Name:	NMK – CB/Relay Maintenance
Completion Date:	June 2022
Project Number:	379284
Project Expenditure:	$ 92 External material $ 19,514 PowerNet services ------------ $ 19,606 Total Cost (2022/23)
Regulatory Classification:	Routine & Corrective Maintenance (Technical Maintenance)
Project Manager:	PowerNet Ltd
Inspection:	PowerNet - Technicians Team

PowerNet is tasked with the planned maintenance and inspection of TPCL Network assets. The inspections are carried out in line with manufacturer's recommendations.

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 2021-2023.

vii. Business Services (Opex)

Administration processes and systems associated with running TPCL network are managed by PowerNet support services teams (eg. Network Assets, Operations, Finance, HSE). A share of these costs are charged to TPCL by way of a management fee, which would otherwise be directly incurred by TPCL, if there was no management agreement 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 TPCL sharing the cost of running these management and administration systems with other EDB's EIL and OJV (economy of scale benefits), was recognised in an independent benchmarking exercise in 2023 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 TPCL favourably against similar sized EDB's in the same peer group.

APPENDIX B:

MAP OF NETWORK EXPENDITURE AND CONSTRAINTS

ID Determination 2.3.13 - 2.3.16

Regulatory requirements

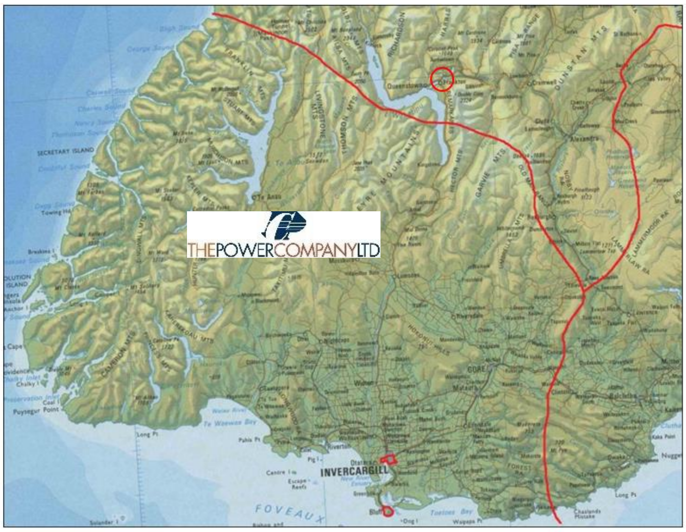
- Electricity Distribution Information Disclosure Determination 2012 (Consolidated in 2023), issued 6 July 2023, clauses 2.3.13 to 2.3.16.

- 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 TPCL network 2023-2033 Asset Management Plan.

TPCL - 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 TPCL network are explained below, and indicated on the Network map above where relative to a single area:

1. Incident Response – Distribution - $34.41m

   Provision is made for staff, plant and resources to be ready for line 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. Distribution Routine Inspections - $13.21 m

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

3. Vegetation Management - $12.25m

   Annual tree trimming in the vicinity of the overhead network to prevent contact with lines, maintaining network reliability.

4. Technical Routine Maintenance - $11.68m

   Following the results of the routine inspection and testing of assets at zone substations, the resulting maintenance work on the substation equipment, switchgear, transformers, and protection relays.

5. Distribution Routine Maintenance -$6.01m

   Refurbishment works for plant other than that located at distribution substations which won't impact on the valuation of the distribution asset. Covers items like cross-arms, insulators, strains, re-sagging lines, stay guards, straightening poles, pole caps, ABS handle replacements etc.

6. Technical Routine Inspections & Checks - $5.11m

   Routine inspection and testing of assets at zone substations. Includes such things as partial discharge surveys on switchgear, oil DGA, breakdown, moisture and acidity, operation counts, protection testing etc.

7. Distribution Routine maintenance - $4.25m

   Routine and planned maintenance on lines, cables, transformers and other distribution components, includes temporary disconnections for customers.

8. Distribution Corrective Maintenance - $4.01m

   Follow up work in the distribution area after the initial incident response work is complete.

9. Technical Corrective Maintenance - $2.48m

   Follow up work in the technical area after the initial incident response work is complete.

10. Incident Reponses Technical - $2.40m

    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.

Further detail relating to TPCL network Operating 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).
- 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).

Possible future constraints related to TPCL network Operating Expenditure projects:

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

TPCL - 10 largest forecast Network Capital Expenditure projects

- 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 TPCL network are explained below, and indicated on the Network map above where relative to a single area:

1. Distribution Line Replacement - $67.21m

   Scheduled for every year, the on-going replacements of distribution 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.

2. Government Decarbonising (GIDI) Funder Projects - $23.50m

   Scheduled for 2024 to 2028 an allowance for future unknown projects including, but not limited to, subtransmission line reinforcements, substation upgrades and changes from 33kV to 66 kV subtransmission. Multiple projects in feasibility, planning and consultation phases as of mid-2023.

3. Earth Upgrades - $21.47m

   Scheduled for every year, ineffective earthing may create hazardous voltage on and around network equipment (Earth Potential Rise; EPR) during fault situations, affecting safety for the public and for staff. Poor earthing can also prevent protection systems from operating correctly, which may affect the safety and reliability of the network. Routine earth site inspection and testing identifies any sites that require upgrades. Determining the most appropriate upgrade option can be quite complex, but the ultimate aim is to find the optimal trade-off between cost and risk reduction. Upgrade works may include additional earthing rods or banks, replacement of surface material (asphalt or gravel) to reduce risk, and installation of insulating fences or fence sections to reduce the risk of transfer to adjacent conductive fences.

4. Distribution Transformer Replacement - $18.79m

   Scheduled for every year, the on-going replacements of distribution transformers which are generally identified during distribution inspections and targeted inspections based on age.

5. Customer Connections (≤ 20kVA) - $15.87m

   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. 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. ABS Renewals - $13.92m

   Scheduled for every year, but decreasing from 2028, ABSs are replaced when inspection indicates deterioration is sufficient enough to lose confidence in continued reliable operation and maintenance is considered uneconomic.

7. Unspecified System Growth Projects - $12.00m

   Scheduled for 2029 – 2033, the project budget is an estimate of costs for projects that are as yet unknown but from experience are considered likely to arise in the longer term (six to ten year time frame). Certainty for these estimates is obviously quite low. Potential ongoing load growth could result in the extension and upgrade of the subtransmission network and conversion of some affected distribution networks to 22kV.

8. New Subdivisions - $10.95m

   Scheduled for every year, planning for new subdivision developments, uses averages based on historical trending, modified by any local knowledge if appropriate however customer requirements are generally unpredictable and quite variable. Various options are considered generally to determine the least cost option for providing the new connection. Work required depends on the development's location relative to existing network and the capacity of that network to supply the additional load. This can range from a simple LV extension for a small development close to a strong supply, through to upgrading of 11 kV cables with new switchgear and transformers. if required.

9. Condition Based Asset Replacements - $10.27m

   Scheduled for 2027 – 2033, these projects include the replacement or refurbishment of equipment arising outside the current asset management plan. Typically used for assets where performance and reliability deteriorates faster than expected and needs to be corrected in the medium term. This will typically occur on assets outside the planned asset management program and where general maintenance will have limited success.
   Typical identification in the short to medium term with implementation from six to ten years.

10. Customer Connections (> 100kVA) - $8.52m

    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. Larger customers especially, which have the greatest effect on the network, tend not to disclose their intentions until connection is required (perhaps trying to avoid alerting competitors to commercial opportunities), 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.

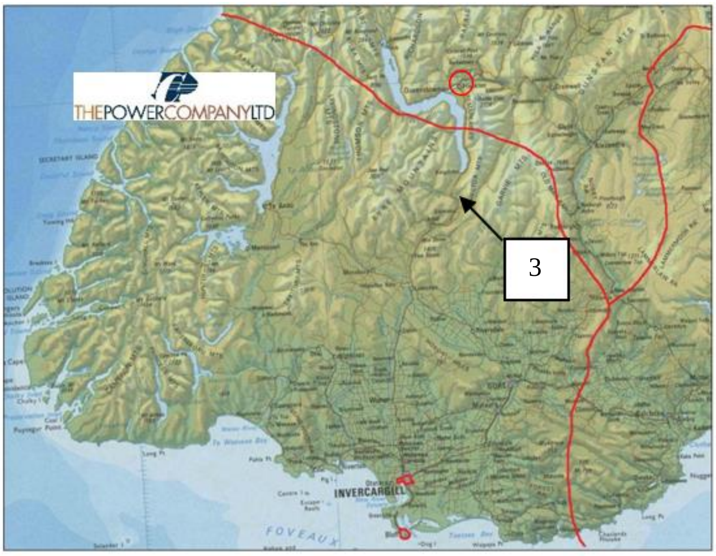
Further detail relating to TPCL network Operating Expenditure in a table at the end of this section.

Please Note: All of these projects -

- Are network wide (apply to entire area as shown on map above);
- 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 TPCL network Capital Expenditure projects:</u>

The following map indicates where potential future constraints may impact the TPCL network performance:



3. <u>Unspecified Projects System Growth</u>

Constraint – Unable to maintain supply voltage due to forecast load growth, timing being 3 - 10 years.

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

- Clause 2.3.13(1), 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	Incident Response - Distribution	Every Year	$34.41m	Network Wide	Yes	Yes	Very likely	N/A
#2	Distribution Routine Inspections	Every Year	$ 13.210m	Network Wide	Yes	Yes	Very likely	N/A
#3	Vegetation Management	Every Year	$ 12.25m	Network Wide	Yes	Yes	Very likely	N/A
#4	Technical Routine Maintenance	Every Year	$ 11.68m	Network Wide	Yes	Yes	Very likely	N/A
#5	Distribution Routine Maintenance	Every Year	$ 6.01m	Network Wide	Yes	Yes	Very likely	N/A
#6	Technical Routine Inspections & Checks	Every Year	$ 5.11m	Network Wide	Yes	Yes	Very likely	N/A
#7	Distribution Routine Maintenance	Every Year	$ 4.25m	Network Wide	Yes	Yes	Very likely	N/A
#8	Distribution Corrective Maintenance	Every Year	$ 4.01m	Network Wide	Yes	Yes	Very likely	N/A
#9	Technical Corrective Maintenance	Every Year	$ 2.48m	Network Wide	Yes	Yes	Very likely	N/A
#10	Incident Response Technical	Every Year	$ 2.40m	Network Wide	Yes	Yes	Very likely	N/A

TPCL - 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	Distribution Line Replacement	Every Year	$ 67.21m	Network Wide	Yes	Yes	Very likely	N/A
#2	Government (GIDI) Funded Projects	2024 - 2028	$ 23.50m	Network Wide	No	N/A	Very likely	N/A
#3	Earth Upgrades	Every Year	$ 23.03m	Network Wide	Yes	N/A	Very likely	N/A
#4	Distribution Transformer Replacement	Every Year	$ 18.79m	Network Wide	Yes	Yes	Very likely	N/A
#5	Customer Connections (≤ 20kVA)	Every Year	$ 15.87m	Network Wide	Yes	Yes	Very likely	N/A
#6	ABS Renewals	Every Year	$ 13.92m	Network Wide	Yes	Yes	Very likely	N/A
#7	Unspecified System Growth Projects	2029 - 2033	$ 10.82m	Network Wide	Yes	Yes	Very likely	N/A
#8	New Subdivisions	Every Year	$ 10.95m	Network Wide	Yes	Yes	Very likely	N/A
#9	Condition Based Asset Replacements	2027-2033	$ 10.27m	Network Wide	Yes	Yes	Very likely	N/A
#10	Customer Connections (≥ 100kVA)	Every Year	$ 8.52m	Network Wide	Yes	Yes	Very likely	N/A

Possible future constraints related to TPCL network Capital Expenditure projects:

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

3. Unspecified Projects System Growth

   Constraint – Unable to maintain supply voltage due to forecast load growth, timing being 7-10 years.

Description of constraint	Related to CapEx project #	Expected timing of constraint
Unable to maintain supply voltage due to forecast load growth	#7	1-2 years

Independent Appraiser's Report

To the Directors of The Power Company Limited and the Commerce Commission

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

We have completed our reasonable assurance engagement in respect of the compliance of The Power Company Limited (the 'Company') 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 Company'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 Company, as specified under the *'Summary of steps and analysis undertaken by the Company 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 Company, as specified under the *'Summary of steps and analysis undertaken by the Company to demonstrate compliance'* are considered to be, in all material respects, reasonable in the circumstances.

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 Company 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.

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Our Approach

Materiality

Our assurance engagement is designed to obtain reasonable assurance about the Company'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 Company'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 Company's related party transactions

We obtained the Company'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 Company 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 Company to demonstrate compliance

The Company 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.

During the year, related party transactions occurred with PowerNet Limited (50% shareholding) (PowerNet) and OtagoNet Joint Venture (75.1% interest) (OJV) .

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 NMAs.
- PowerNet subcontracts external parties to assist it in providing these services where appropriate.
- PowerNet recovers its costs from TPC 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	4,367
ii.	Vegetation management	1,380
iii.	Routine and corrective maintenance and inspection	4,456
iv.	Asset replacement and renewal (Opex)	642
v.	System operations and network support	2,249
vi.	Business support	3,045
Total Operating Expenditure		**16,139**

Capital Expenditure:

i.	Consumer connection	13,101
ii.	System growth	3,278
iii.	Asset replacement and renewal (Capex)	11,263
iv.	Asset relocations	285
v.	Quality of supply	576
vi.	Other reliability, safety and environment	3,735
Total Capital Expenditure		**32,238**
Total Related Party Expenditure		**48,377**

During the year TPC received $60,000 from OJV in relation to 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 TPC's identification of any " unregulated parts" of the entity.

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

Summary of steps undertaken by the Company to demonstrate compliance

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

While TPCL owns the Network Assets and provides electricity distribution services through their network across Southland (excluding parts of Invercargill city and the Bluff township area), under the agreement PowerNet will manage the network assets, will carry out an agreed capital works programme, has the exclusive right to provide line function services, and will provide the business administration services on behalf of TPCL.

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 Electricity Invercargill Limited (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 acknowledged 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 a Network Management Fee to the EDB's and metering businesses it manages under the NMA's. These charges recover costs incurred in the performance of the system control services, asset management, corporate, finance and commercial services.

These network management 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 management fee charged to the EDB's and metering businesses and
- the mark-up applied to capital expenditure to recover costs allocated to EDB and meter capital projects

An independent review in 2018 of the allocation methodology ensured all parties that are charged agency and other fees by PowerNet are treated consistently and appropriately for each party.

Our Procedures Undertaken

The background information provided by TPC is in line with our understanding of the intent behind the group structure and agency/ management agreement between TPC 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 TPC Board;
- External reports obtained and presented to the TPC 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 TPC 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 international 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 Company to demonstrate compliance

TPC 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 TPC under the NMA.

TPC 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 TPC 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 TPC 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 TPC 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*
   TPC is related to PowerNet by way of 50% ownership share, however with regards to acting independently, PowerNet operates with the level of independence of a separate entity, due to the other 50% ownership being held by separately owned EIL. Each entity has its own 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 TPC's capital expenditure and 90% of TPC's operating expenditure for the year ended 31 March 2023. Whilst PowerNet performs the majority of TPC's capital and operating expense work, we note that 29% of the costs related to external materials and labour (Excl. markups) obtained at an arm's length.

We have performed the following procedures over TPC's 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 TPC 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 TPC is at or below the charges to external customers.

iii. *Acting independently*
We note even though TPC, EIL and PowerNet all have individual boards acting independently there are some common Directors across the Boards. 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 TPC 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 TPC pursue its own best interests?

- It ensures PowerNet's other customers do not receive favourable terms;
- It monitors the performance of PowerNet; and
- It approves PowerNet's work plans for its network.

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

Summary of steps undertaken by the Company to demonstrate compliance

The independent and objective measures used by TPC 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 Company'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 TPC 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 TPC to gain comfort over the appropriateness of and level of comfort obtained from the independent and objective measures provided:

External labour & materials (Opex $3.1m and Capex $18.9m)

- 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 $0.4m and Capex $5m)

- Obtained the NMA and minutes of TPC board meetings and noted approval by the TPC Board of the cost allocation methods;
- Obtained mark-up comparison published documentation between three competitors, noting consistent external contractor services and materials mark-up 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 comparable 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 $7.6m and Capex $8.2m)

- We obtained subsequent benchmarking performed by TPC 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 TPC 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 TPC. 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 $5.3m)

- 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 TPC business plan FY22/23 and note approval by the TPC 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 TPC'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 Company 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 Company 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 Company'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 Company. Our firm carries out other services for the Company in the areas of compliance with the Electricity Distribution (Information Disclosure) Determination 2012, other regulatory requirements of the Commerce Act 1986, audit of the financial statements and provision of regulatory training and advisory services. 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 Directors of the Company and for the Commerce Commission for the purpose of providing those parties with reasonable assurance on whether:

- the Company's 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 Company, as specified under the "Summary of steps and analysis undertaken by the Company 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 Company 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 Directors of The Power Company Limited 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 The Power Company Limited (the "Company") 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 Company 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 Company'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 Company's recording of SAIDI, SAIFI, and number of interruptions due to successive interruptions.

Qualified Opinion

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

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

Basis for Qualified Opinion

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

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

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

We 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 Company'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 Company 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 Company 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 The Power Company Limited's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Determination. It is a measure which is used widely and is key to measuring The Power Company Limited's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the IM Determination, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration. Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus.	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. **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

Key Assurance Matter	How our procedures addressed the key assurance matter
	● 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 Power Company Limited to value its transactions with related parties, disclosed in Schedule 5b, in accordance with the principles-based approach to the arm's length valuation rule. This rule states that the value of goods or services acquired from a related party cannot be greater than if it had been acquired under the terms of an arm's length transaction with an unrelated party, nor may it exceed the actual cost to the related party. A sale or supply to a related party cannot be valued at an amount less than if it had been sold or supplied under the terms of an arm's-length transaction with an unrelated party. 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. The Power Company Limited is required to use an objective and independent measure to demonstrate compliance with the arm's-length principle. In the absence of an active market for similar transactions, assigning an objective arm's length value to a related party transaction is	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 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 The Power Company Limited's assessment of available independent and objective measures used in supporting the arm's length valuation principal and performed the following procedures: ● Re-performed the calculations within The Power Company Limited's benchmarking assessment and agreed key inputs and assumptions to supporting documentation; ● Where benchmarking or other market information was used as independent and objective measures, we assessed whether the related party transaction values fell within a reasonable range. Qualitative factors were

Key Assurance Matter	How our procedures addressed the key assurance matter
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.	considered in determining the appropriate acceptable range.

Directors Responsibilities

The Directors are responsible on behalf of the Company 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 Company'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 The Power Company. Our firm carries out other services for the Company in the areas of compliance with the Electricity Distribution (Information Disclosure) Determination 2012, other regulatory requirements of the Commerce Act 1986, audit of the financial statements and provision of regulatory training and advisory services. 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 Company 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 Company 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 Company'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 Directors 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 Directors of the Company, 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

5. Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Peter William Moynihan and Murray John Wallace, being directors of The Power Company Limited certify that, having made all reasonable enquiry, to the best of our knowledge-

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

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

c) in respect of information concerning assets, costs and revenues valued or disclosed in accordance with clause 2.3.6 of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012, we are satisfied that-
   i. the costs and values of assets or goods or services acquired from a related party comply, in all material respects, with clauses 2.3.6(1) and 2.3.6(3) of the Electricity Distribution Information Disclosure Determination 2012 and clauses 2.2.11(1)(g) and 2.2.11(5)(a)-2.2.11(5)(b) of the Electricity Distribution Services Input Methodologies Determination 2012; and
   ii. the value of assets or goods or services sold or supplied to a related party comply, in all material respects, with clause 2.3.6(2) of the Electricity Distribution Information Disclosure Determination 2012.

Peter William Moynihan

31 August 2023

Murray John Wallace

31 August 2023

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

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