THEPOWERCOMPANYLTD

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

FOR THE YEAR ENDED 31 MARCH 2020

CONTENTS

1. INTRODUCTION

These Information Disclosure documents are submitted by 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 2020**

SCHEDULE 1: ANALYTICAL RATIOS

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

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

sch ref

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

sch ref		Expenditure per GWh energy delivered to ICPs ($/GWh)	Expenditure per average no. of ICPs ($/ICP)	Expenditure per MW maximum coincident system demand ($/MW)	Expenditure per km circuit length ($/km)	Expenditure per MVA of capacity from EDB-owned distribution transformers ($/MVA)
8						
9	**Operational expenditure**	23,293	476	117,764	1,955	37,889
10	Network	15,487	317	78,301	1,300	25,193
11	Non-network	7,805	160	39,463	655	12,697
12						
13	**Expenditure on assets**	35,516	726	179,559	2,981	57,772
14	Network	35,516	726	179,559	2,981	57,772
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**	85,531	1,749
20	Standard consumer line charge revenue	94,124	1,598
21	Non-standard consumer line charge revenue	43,572	1,098,857
22			

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

sch ref			
24			
25	Demand density	17	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26	Volume density	84	*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	20,446	*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	17,279	27.16%
33	Pass-through and recoverable costs excluding financial incentives and wash-ups	13,904	21.86%
34	Total depreciation	14,313	22.50%
35	Total revaluations	9,710	15.26%
36	Regulatory tax allowance	3,664	5.76%
37	Regulatory profit/(loss) including financial incentives and wash-ups	23,969	37.68%
38	**Total regulatory income**	63,615	
39			

40 **1(v): Reliability**

sch ref			
41			
42	Interruption rate	14.11	*Interruptions per 100 circuit km*

Company Name	The Power Company Limited
For Year Ended	31 March 2020

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

This schedule requires information on the Return on Investment (ROI) for the EDB relative to the Commerce Commission's estimates of post tax WACC and vanilla WACC. EDBs must calculate their ROI based on a monthly basis if required by clause 2.3.3 of the ID Determination or if they elect to. If an EDB makes this election, information supporting this calculation must be provided in 2(iii).

EDBs must provide explanatory comment on their ROI in Schedule 14 (Mandatory Explanatory Notes).

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

sch ref

2(i): Return on Investment

	CY-2	CY-1	Current Year CY
	31 Mar 18	31 Mar 19	31 Mar 20
ROI – comparable to a post tax WACC	%	%	%
Reflecting all revenue earned	4.39%	4.98%	6.04%
Excluding revenue earned from financial incentives	4.39%	4.98%	6.04%
Excluding revenue earned from financial incentives and wash-ups	4.39%	4.98%	6.04%
Mid-point estimate of post tax WACC	5.04%	4.75%	4.27%
25th percentile estimate	4.36%	4.07%	3.59%
75th percentile estimate	5.72%	5.43%	4.95%
ROI – comparable to a vanilla WACC			
Reflecting all revenue earned	4.98%	5.49%	6.47%
Excluding revenue earned from financial incentives	4.98%	5.49%	6.47%
Excluding revenue earned from financial incentives and wash-ups	4.98%	5.49%	6.47%
WACC rate used to set regulatory price path	NA	NA	NA
Mid-point estimate of vanilla WACC	5.60%	5.26%	4.69%
25th percentile estimate	4.92%	4.58%	4.01%
75th percentile estimate	6.29%	5.94%	5.37%

2(ii): Information Supporting the ROI

			($000)	
	Total opening RAB value	385,009		
plus	Opening deferred tax	(18,533)		
Opening RIV			366,476	
Line charge revenue			63,450	
	Expenses cash outflow	31,183		
add	Assets commissioned	28,192		
less	Asset disposals	616		
add	Tax payments	1,443		
less	Other regulated income	165		
Mid-year net cash outflows			60,037	
Term credit spread differential allowance			198	
	Total closing RAB value	407,982		
less	Adjustment resulting from asset allocation	(0)		
less	Lost and found assets adjustment	–		
plus	Closing deferred tax	(20,753)		
Closing RIV			387,230	
ROI – comparable to a vanilla WACC				6.47%
	Leverage (%)			42%
	Cost of debt assumption (%)			3.61%
	Corporate tax rate (%)			28%
ROI – comparable to a post tax WACC				6.04%

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	6.30%
Year-end ROI – comparable to a post tax WACC	5.87%

** 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		–

Company Name	The Power Company Limited
For Year Ended	31 March 2020

SCHEDULE 3: REPORT ON REGULATORY PROFIT

This schedule requires information on the calculation of regulatory profit for the EDB for the disclosure year. All EDBs must complete all sections and provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).

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

sch ref			($000)
7		**3(i): Regulatory Profit**	
8		**Income**	
9		Line charge revenue	63,450
10	*plus*	Gains / (losses) on asset disposals	(549)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	714
12			
13		**Total regulatory income**	63,615
14		**Expenses**	
15	*less*	Operational expenditure	17,279
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	13,904
18			
19		**Operating surplus / (deficit)**	32,431
20			
21	*less*	Total depreciation	14,313
22			
23	*plus*	Total revaluations	9,710
24			
25		**Regulatory profit / (loss) before tax**	27,829
26			
27	*less*	Term credit spread differential allowance	198
28			
29	*less*	Regulatory tax allowance	3,663
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	23,968
32			

		($000)	
33	**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**		
34	**Pass through costs**		
35	Rates	217	
36	Commerce Act levies	64	
37	Industry levies	131	
38	CPP specified pass through costs	–	
39	**Recoverable costs excluding financial incentives and wash-ups**		
40	Electricity lines service charge payable to Transpower	13,255	
41	Transpower new investment contract charges	238	
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**		13,904
47			

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

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

Company Name	The Power Company Limited
For Year Ended	31 March 2020

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

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

sch ref

sch ref	4(i): Regulatory Asset Base Value (Rolled Forward)	RAB	RAB	RAB	RAB	RAB
8	for year ended	31 Mar 16	31 Mar 17	31 Mar 18	31 Mar 19	31 Mar 20
9		($000)	($000)	($000)	($000)	($000)
10	**Total opening RAB value**	325,146	339,946	355,086	373,678	385,009
11						
12	*less* **Total depreciation**	12,233	12,755	12,615	13,762	14,313
13						
14	*plus* **Total revaluations**	1,900	7,349	3,886	5,526	9,710
15						
16	*plus* **Assets commissioned**	25,526	20,976	25,100	20,360	28,192
17						
18	*less* **Asset disposals**	393	429	744	792	616
19						
20	*plus* **Lost and found assets adjustment**	–	–	2,964	–	–
21						
22	*plus* **Adjustment resulting from asset allocation**	–	–	–	–	(0)
23						
24	**Total closing RAB value**	339,946	355,086	373,678	385,009	407,982
25						

sch ref	4(ii): Unallocated Regulatory Asset Base	Unallocated RAB *		RAB	
28		($000)	($000)	($000)	($000)
29	**Total opening RAB value**		385,009		385,009
30	*less*				
31	**Total depreciation**		14,313		14,313
32	*plus*				
33	**Total revaluations**		9,710		9,710
34	*plus*				
35	Assets commissioned (other than below)	–		–	
36	Assets acquired from a regulated supplier	–		–	
37	Assets acquired from a related party	28,192		28,192	
38	**Assets commissioned**		28,192		28,192
39	*less*				
40	Asset disposals (other than below)	572		572	
41	Asset disposals to a regulated supplier	–		–	
42	Asset disposals to a related party	45		45	
43	**Asset disposals**		616		616
44					
45	*plus* **Lost and found assets adjustment**		–		–
46					
47	*plus* **Adjustment resulting from asset allocation**				(0)
48					
49	**Total closing RAB value**		407,982		407,982

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

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

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

		Unallocated RAB *		RAB	
		($000)	($000)	($000)	($000)
	Total opening RAB value	385,009		385,009	
less	Opening value of fully depreciated, disposed and lost assets	1,826		1,826	
	Total opening RAB value subject to revaluation	383,182		383,183	
	Total revaluations		9,710		9,710

4(iv): Roll Forward of Works Under Construction

		Unallocated works under construction		Allocated works under construction	
	Works under construction—preceding disclosure year		15,181		15,181
plus	Capital expenditure	23,159		23,159	
less	Assets commissioned	28,192		28,192	
plus	Adjustment resulting from asset allocation				
	Works under construction - current disclosure year		10,148		10,148
	Highest rate of capitalised finance applied				

4(v): Regulatory Depreciation

	Unallocated RAB *		RAB	
	($000)	($000)	($000)	($000)
Depreciation - standard	14,313		14,313	
Depreciation - no standard life assets	–		–	
Depreciation - modified life assets	–		–	
Depreciation - alternative depreciation in accordance with CPP	–		–	
Total depreciation		14,313		14,313

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	58,332	2,383	97,946	133,191	19,219	53,633	13,202	7,096	7	385,009
less	Total depreciation	1,828	62	3,468	5,842	646	1,651	576	239		14,313
plus	Total revaluations	1,475	61	2,478	3,351	482	1,349	334	180		9,710
plus	Assets commissioned	2,823	1,939	8,518	8,668	951	3,008	1,957	327		28,192
less	Asset disposals			36			542	38			616
plus	Lost and found assets adjustment										–
plus	Adjustment resulting from asset allocation										–
plus	Asset category transfers										–
	Total closing RAB value	60,803	4,321	105,438	139,369	20,007	55,796	14,879	7,363	7	407,982

	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	
Asset Life										
Weighted average remaining asset life	26.6	38.1	34.0	24.3	43.7	33.8	25.0	16.7	–	(years)
Weighted average expected total asset life	57.0	45.8	45.8	58.1	62.3	47.1	39.6	32.3	–	(years)

Company Name	The Power Company Limited
For Year Ended	31 March 2020

SCHEDULE 5a: REPORT ON REGULATORY TAX ALLOWANCE

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

sch ref					
7	**5a(i): Regulatory Tax Allowance**				**($000)**
8		**Regulatory profit / (loss) before tax**			27,829
9					
10	*plus*	Income not included in regulatory profit / (loss) before tax but taxable	–	*	
11		Expenditure or loss in regulatory profit / (loss) before tax but not deductible	–	*	
12		Amortisation of initial differences in asset values	6,995		
13		Amortisation of revaluations	1,414		
14					8,409
15					
16	*less*	Total revaluations	9,710		
17		Income included in regulatory profit / (loss) before tax but not taxable	–	*	
18		Discretionary discounts and customer rebates	7,790		
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax	2	*	
20		Notional deductible interest	5,653		
21					23,155
22					
23		**Regulatory taxable income**			13,083
24					
25	*less*	Utilised tax losses	–		
26		Regulatory net taxable income			13,083
27					
28		Corporate tax rate (%)	28%		
29		**Regulatory tax allowance**			3,663
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	125,904		
37	*less*	Amortisation of initial differences in asset values	6,995		
38	*plus*	Adjustment for unamortised initial differences in assets acquired	–		
39	*less*	Adjustment for unamortised initial differences in assets disposed	455		
40		Closing unamortised initial differences in asset values			118,454
41					
42		Opening weighted average remaining useful life of relevant assets (years)			18
43					

5a(iv): Amortisation of Revaluations

			($000)
	Opening sum of RAB values without revaluations	349,055	
	Adjusted depreciation	12,898	
	Total depreciation	14,313	
	Amortisation of revaluations		1,414

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	(18,533)	
plus	Tax effect of adjusted depreciation	3,612	
less	Tax effect of tax depreciation	4,555	
plus	Tax effect of other temporary differences*	609	
less	Tax effect of amortisation of initial differences in asset values	1,959	
plus	Deferred tax balance relating to assets acquired in the disclosure year	–	
less	Deferred tax balance relating to assets disposed in the disclosure year	(72)	
plus	Deferred tax cost allocation adjustment	0	
	Closing deferred tax		(20,753)

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	167,639	
less	Tax depreciation	16,266	
plus	Regulatory tax asset value of assets commissioned	31,185	
less	Regulatory tax asset value of asset disposals	243	
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		182,315

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2020**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

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

sch ref		($000)	($000)
7	**5b(i): Summary—Related Party Transactions**		
8	**Total regulatory income**		9
9			
10	**Market value of asset disposals**		45
11			
12	Service interruptions and emergencies	4,477	
13	Vegetation management	1,592	
14	Routine and corrective maintenance and inspection	4,779	
15	Asset replacement and renewal (opex)	641	
16	**Network opex**		11,489
17	Business support	2,876	
18	System operations and network support	1,545	
19	**Operational expenditure**		15,910
20	Consumer connection	4,718	
21	System growth	3,668	
22	Asset replacement and renewal (capex)	12,968	
23	Asset relocations	209	
24	Quality of supply	1,240	
25	Legislative and regulatory	–	
26	Other reliability, safety and environment	3,543	
27	**Expenditure on non-network assets**		–
28	**Expenditure on assets**		26,346
29	Cost of financing		–
30	Value of capital contributions		–
31	Value of vested assets		–
32	**Capital Expenditure**		26,346
33	**Total expenditure**		42,256
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	4,477
39	PowerNet Limited	Vegetation management	1,592
40	PowerNet Limited	Routine and corrective maintenance and inspection	4,779
41	PowerNet Limited	Asset replacement and renewal (opex)	641
42	PowerNet Limited	System operations and network support	1,545
43	PowerNet Limited	Business support	2,876
44	PowerNet Limited	Consumer connection	4,718
45	PowerNet Limited	System growth	3,668
46	PowerNet Limited	Asset replacement and renewal (capex)	12,968
47	PowerNet Limited	Asset relocations	209
48	PowerNet Limited	Quality of supply	1,240
49	PowerNet Limited	Other reliability, safety and environment	3,543
50			
51			
52			
53	**Total value of related party transactions**		42,256
54	** include additional rows if needed*		
55			

Company Name	The Power Company Limited
For Year Ended	31 March 2020

SCHEDULE 5c: REPORT ON TERM CREDIT SPREAD DIFFERENTIAL ALLOWANCE

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

sch ref

7

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

9

sch ref	Issuing party	Issue date	Pricing date	Original tenor (in years)	Coupon rate (%)	Book value at issue date (NZD)	Book value at date of financial statements (NZD)	Term Credit Spread Difference	Debt issue cost readjustment
11	US Private Placement (USPP) US $40M	4/2/2020	7/11/2019	10.0	BKBM plus margin	62,794	74,552	235	(63)
12	US Private Placement (USPP) US $25M	4/2/2020	7/11/2019	11.0	BKBM plus margin	39,246	47,040	177	(43)
13									
14									
15									
16	** include additional rows if needed*						121,592	412	(106)

17

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

19

sch ref			
20	**Gross term credit spread differential**		306
21			
22	Total book value of interest bearing debt	257,742	
23	Leverage	42%	
24	Average opening and closing RAB values	396,496	
25	**Attribution Rate (%)**		65%
26			
27	**Term credit spread differential allowance**		198

Company Name: The Power Company Limited
For Year Ended: 31 March 2020

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

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)				
10	**Service interruptions and emergencies**					
11	Directly attributable		4,477			
12	Not directly attributable				–	
13	**Total attributable to regulated service**		4,477			
14	**Vegetation management**					
15	Directly attributable		1,592			
16	Not directly attributable				–	
17	**Total attributable to regulated service**		1,592			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		4,779			
20	Not directly attributable				–	
21	**Total attributable to regulated service**		4,779			
22	**Asset replacement and renewal**					
23	Directly attributable		641			
24	Not directly attributable				–	
25	**Total attributable to regulated service**		641			
26	**System operations and network support**					
27	Directly attributable		2,171			
28	Not directly attributable				–	
29	**Total attributable to regulated service**		2,171			
30	**Business support**					
31	Directly attributable		3,097			
32	Not directly attributable		496	27	523	
33	**Total attributable to regulated service**		3,593			
34						
35	**Operating costs directly attributable**		16,756			
36	**Operating costs not directly attributable**	–	496	27	523	–
37	**Operational expenditure**		17,252			
38						

39 **5d(ii): Other Cost Allocations**

sch ref		($000)
40	**Pass through and recoverable costs**	
41	**Pass through costs**	
42	Directly attributable	412
43	Not directly attributable	
44	**Total attributable to regulated service**	412
45	**Recoverable costs**	
46	Directly attributable	13,493
47	Not directly attributable	–
48	**Total attributable to regulated service**	13,493
49		

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

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

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

pwc

Company Name	The Power Company Limited
For Year Ended	31 March 2020

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

5e(i): Regulated Service Asset Values

sch ref		Value allocated ($000s) Electricity distribution services
7	**5e(i): Regulated Service Asset Values**	
8		Value allocated ($000s)
9		Electricity distribution services
10	**Subtransmission lines**	
11	Directly attributable	60,803
12	Not directly attributable	–
13	**Total attributable to regulated service**	60,803
14	**Subtransmission cables**	
15	Directly attributable	4,321
16	Not directly attributable	–
17	**Total attributable to regulated service**	4,321
18	**Zone substations**	
19	Directly attributable	105,438
20	Not directly attributable	–
21	**Total attributable to regulated service**	105,438
22	**Distribution and LV lines**	
23	Directly attributable	139,369
24	Not directly attributable	–
25	**Total attributable to regulated service**	139,369
26	**Distribution and LV cables**	
27	Directly attributable	20,007
28	Not directly attributable	–
29	**Total attributable to regulated service**	20,007
30	**Distribution substations and transformers**	
31	Directly attributable	55,796
32	Not directly attributable	–
33	**Total attributable to regulated service**	55,796
34	**Distribution switchgear**	
35	Directly attributable	14,879
36	Not directly attributable	–
37	**Total attributable to regulated service**	14,879
38	**Other network assets**	
39	Directly attributable	7,363
40	Not directly attributable	–
41	**Total attributable to regulated service**	7,363
42	**Non-network assets**	
43	Directly attributable	7
44	Not directly attributable	–
45	**Total attributable to regulated service**	7
46		
47	**Regulated service asset value directly attributable**	407,982
48	**Regulated service asset value not directly attributable**	–
49	**Total closing RAB value**	407,982
50		

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

sch ref				CY-1 ($000)	Current Year (CY) ($000)
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 2020

SCHEDULE 5f: REPORT SUPPORTING COST ALLOCATIONS

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

sch ref	Line Item*	Allocation methodology type	Cost allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
7											
8											
11	**Service interruptions and emergencies**										
12										-	
13										-	
14										-	
15										-	
16	**Not directly attributable**						-	-	-	-	-
17	**Vegetation management**										
18										-	
19										-	
20										-	
21										-	
22	**Not directly attributable**						-	-	-	-	-
23	**Routine and corrective maintenance and inspection**										
24										-	
25										-	
26										-	
27										-	
28	**Not directly attributable**						-	-	-	-	-
29	**Asset replacement and renewal**										
30										-	
31										-	
32										-	
33										-	
34	**Not directly attributable**						-	-	-	-	-
35											
36	**System operations and network support**										
37										-	
38										-	
39										-	
40										-	
41	**Not directly attributable**						-	-	-	-	-
42	**Business support**										
43	Administration expenses	ABAA	Revenue	Proxy	94.79%	5.21%		496	27	523	
44										-	
45										-	
46										-	
47	**Not directly attributable**						-	496	27	523	-
48											
49	**Operating costs not directly attributable**						-	496	27	523	-
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*										

pwc

Company Name: **The Power Company Limited**
For Year Ended: **31 March 2020**

SCHEDULE 5g: REPORT SUPPORTING ASSET ALLOCATIONS

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

sch ref	Line Item*	Allocation methodology type	Allocator	Allocator type	Allocator Metric (%)		Value allocated ($000)				OVABAA allocation increase ($000)
					Electricity distribution services	Non-electricity distribution services	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	
7											
8											
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 2020**

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

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

sch ref				
7		**6a(i): Expenditure on Assets**	**($000)**	**($000)**
8		Consumer connection		4,718
9		System growth		3,668
10		Asset replacement and renewal		12,968
11		Asset relocations		209
12		Reliability, safety and environment:		
13		Quality of supply	1,240	
14		Legislative and regulatory	–	
15		Other reliability, safety and environment	3,543	
16		**Total reliability, safety and environment**		4,783
17		**Expenditure on network assets**		26,346
18		Expenditure on non-network assets		–
19				
20		**Expenditure on assets**		26,346
21	*plus*	Cost of financing		–
22	*less*	Value of capital contributions		3,188
23	*plus*	Value of vested assets		–
24				
25		**Capital expenditure**		23,159
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**		**($000)**
27		Energy efficiency and demand side management, reduction of energy losses		–
28		Overhead to underground conversion		–
29		Research and development		–
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**	**($000)**	**($000)**
32		Non Half Hour Individuals	3,133	
33		Non- Domestic	438	
34		Domestic	1,147	
35				
36				
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		4,718
39				
40	*less*	Capital contributions funding consumer connection expenditure	2,682	
41		**Consumer connection less capital contributions**		2,036
42		**6a(iv): System Growth and Asset Replacement and Renewal**		**Asset Replacement**
43			**System Growth**	**and Renewal**
44			**($000)**	**($000)**
45		Subtransmission	2,009	467
46		Zone substations	718	679
47		Distribution and LV lines	10	6,296
48		Distribution and LV cables	830	18
49		Distribution substations and transformers		3,838
50		Distribution switchgear		998
51		Other network assets	101	672
52		**System growth and asset replacement and renewal expenditure**	3,668	12,968
53	*less*	Capital contributions funding system growth and asset replacement and renewal		178
54		**System growth and asset replacement and renewal less capital contributions**	3,668	12,790
55				
56		**6a(v): Asset Relocations**		
57		*Project or programme**	**($000)**	**($000)**
58		Line relocations	209	
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other projects or programmes - asset relocations	–	
65		**Asset relocations expenditure**		209
66	*less*	Capital contributions funding asset relocations	146	
67		**Asset relocations less capital contributions**		63

6a(vi): Quality of Supply

	Project or programme*	($000)	($000)
	Mobile Substation Made Ready	709	
	* include additional rows if needed		
	All other projects programmes - quality of supply	531	
	Quality of supply expenditure		1,240
less	Capital contributions funding quality of supply	182	
	Quality of supply less capital contributions		1,058

6a(vii): Legislative and Regulatory

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

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

	Project or programme*	($000)	($000)
	Earth Upgrades	1,384	
	NER Installations	388	
	Switchgear replacement	531	
	33 kv Back Up Supply	473	
	* include additional rows if needed		
	All other projects or programmes - other reliability, safety and environment	767	
	Other reliability, safety and environment expenditure		3,543
less	Capital contributions funding other reliability, safety and environment		
	Other reliability, safety and environment less capital contributions		3,543

6a(ix): Non-Network Assets

Routine expenditure

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

Atypical expenditure

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

Company Name	The Power Company Limited
For Year Ended	31 March 2020

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

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

sch ref			
7	**6b(i): Operational Expenditure**	**($000)**	**($000)**
8	Service interruptions and emergencies	4,477	
9	Vegetation management	1,592	
10	Routine and corrective maintenance and inspection	4,779	
11	Asset replacement and renewal	641	
12	**Network opex**		11,489
13	System operations and network support	2,171	
14	Business support	3,620	
15	**Non-network opex**		5,790
16			
17	**Operational expenditure**		17,279
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		125
20	Direct billing*		–
21	Research and development		–
22	Insurance		337
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2020**

SCHEDULE 7: COMPARISON OF FORECASTS TO ACTUAL EXPENDITURE

This schedule compares actual revenue and expenditure to the previous forecasts that were made for the disclosure year. Accordingly, this schedule requires the forecast revenue and expenditure information from previous disclosures to be inserted.

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

sch ref				
7	**7(i): Revenue**	**Target ($000) [1]**	**Actual ($000)**	**% variance**
8	Line charge revenue	61,681	63,450	3%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	3,385	4,718	39%
11	System growth	4,724	3,668	(22%)
12	Asset replacement and renewal	12,721	12,968	2%
13	Asset relocations	516	209	(59%)
14	Reliability, safety and environment:			
15	Quality of supply	923	1,240	34%
16	Legislative and regulatory	–	–	–
17	Other reliability, safety and environment	2,836	3,543	25%
18	**Total reliability, safety and environment**	3,759	4,783	27%
19	**Expenditure on network assets**	25,104	26,346	5%
20	Expenditure on non-network assets	835	–	(100%)
21	Expenditure on assets	25,939	26,346	2%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	4,475	4,477	0%
24	Vegetation management	1,799	1,592	(12%)
25	Routine and corrective maintenance and inspection	5,351	4,779	(11%)
26	Asset replacement and renewal	1,407	641	(54%)
27	**Network opex**	13,032	11,489	(12%)
28	System operations and network support	2,812	2,171	(23%)
29	Business support	3,763	3,620	(4%)
30	**Non-network opex**	6,575	5,790	(12%)
31	**Operational expenditure**	19,607	17,279	(12%)
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	224	–	(100%)
34	Overhead to underground conversion	–	–	–
35	Research and development	–	–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	125	125	–
39	Direct billing	–	–	–
40	Research and development	–	–	–
41	Insurance	998	337	(66%)
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 2020
Network / Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8 **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 day energy purchases				
13					Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)	kWh	KWh				
15	Low user	Residential	Standard	10,075	60,579		49,979,367				
16	Domestic	Residential	Standard	16,705	155,461		125,075,237				
17	Non-Domestic	Commerical	Standard	9,226	206,903		165,306,362				
18	Individual non half hour	Commerical	Standard	71	9,768		7,834,840				
19	Individual half hour	Commerical	Standard	200	183,022	122,667,944					
20	Non-Standard	Commerical	Non-standard	3	125,752	90,668,192					
21	Generation	Commerical	Non-standard	2	343	234,136					
22											
23											
24											
26			Standard consumer totals	36,277	615,734	122,667,944	348,195,806	–	–	–	–
27			Non-standard consumer totals	5	126,095	90,902,328	–	–	–	–	–
28			Total for all consumers	36,282	741,829	213,570,271	348,195,806	–	–	–	–

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

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

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

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Total line charge revenue in disclosure year	Notional revenue foregone from posted discounts (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Line charge revenues ($000) by price component					
						Price component	Fixed	Variable				
						Rate (eg, $ per day, $ per kWh, etc.)	$/Day	$/kwh				
Low user	Residential	Standard	$7,454		$6,268	$1,186	$413	$7,040				
Domestic	Residential	Standard	$19,497		$16,392	$3,105	$8,495	$11,002				
Non-Domestic	Commerical	Standard	$24,086		$20,204	$3,882	$9,677	$14,409				
Individual non half hour	Commerical	Standard	$755		$519	$236	$66	$689				
Individual half hour	Commerical	Standard	$6,164		$3,018	$3,146	$3,432	$2,732				
Non-Standard	Commerical	Non-standard	$3,498		$2,245	$1,253	$3,498					
Generation	Commerical	Non-standard	$1,997		$1,312	$685	$1,997					
			–									
			–									
			–									
		Standard consumer totals	$57,955	–	$46,401	$11,554	$22,083	$35,872	–	–	–	–
		Non-standard consumer totals	$5,494	–	$3,556	$1,938	$5,494	–	–	–	–	–
		Total for all consumers	$63,450	–	$49,957	$13,493	$27,578	$35,872	–	–	–	–

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

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

8(iii): Number of ICPs directly billed

Check: OK

Number of directly billed ICPs at year end	5

Company Name	The Power Company Limited
For Year Ended	31 March 2020
Network / Sub-network Name	

SCHEDULE 9a: ASSET REGISTER

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

sch ref

8	Voltage	Asset category	Asset class	Units	Items at start of year (quantity)	Items at end of year (quantity)	Net change	Data accuracy (1–4)
9	All	Overhead Line	Concrete poles / steel structure	No.	89,884	90,759	875	3
10	All	Overhead Line	Wood poles	No.	19,254	18,588	(666)	3
11	All	Overhead Line	Other pole types	No.	–	–	–	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	898	907	10	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	8	11	3	3
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	1	1	–	3
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.	54	58	4	3
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	N/A
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	58	58	–	3
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	8	8	–	3
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	292	294	2	3
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	20	20	–	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	30	30	–	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	148	150	2	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	48	47	(1)	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	62	62	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	6,710	6,808	98	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	8	8	(0)	3
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	111	116	5	3
39	HV	Distribution Cable	Distribution UG PILC	km	42	37	(4)	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.	35	32	(3)	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	7	15	8	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	13,719	13,798	79	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.	97	102	5	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	10,504	10,543	39	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	659	674	15	3
48	HV	Distribution Transformer	Voltage regulators	No.	71	72	1	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	7	7	–	3
50	LV	LV Line	LV OH Conductor	km	849	846	(3)	3
51	LV	LV Cable	LV UG Cable	km	231	213	(18)	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	353	354	1	3
53	LV	Connections	OH/UG consumer service connections	No.	37,775	38,039	264	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	586	593	7	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 2020
Network / Sub-network Name	

SCHEDULE 9b: ASSET AGE PROFILE

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

sch ref

8 Disclosure Year (year ended): 31 March 2020

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006
10	All	Overhead Line	Concrete poles / steel structure	No.	–	–	2,210	36,393	12,107	21,137	2,976	204	759	991	605	174	85	138
11	All	Overhead Line	Wood poles	No.	–	–	536	1,334	4,779	697	3,626	732	794	738	756	731	449	866
12	All	Overhead Line	Other pole types	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	129	133	127	140	137	59	35	8	26	–	–	0
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	–	1	–	0	1	0	0	1	–
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	1	–	–	–	–	–	–	–	–
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	2	7	10	7	6	–	2	1	–	–	–	–
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	11	6	1	–	–	2	2	2
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	18	12	14	29	62	3	35	2	3	12	7	10
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	7	–	–	–	5
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	–	2	1	3	6	2	–	–	–	–	1	2
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	–	–	17	49	–	–	1	–	–	–	–
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	3	20	6	–	–	1	4	1	1
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	–	6	8	9	2	1	3	2	1	3	–	2
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3	0	203	728	3,342	1,080	312	47	98	102	70	61	57	54
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
38	HV	Distribution Line	SWER conductor	km	–	–	–	4	1	–	–	–	–	–	–	–	–	–
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	0	16	4	5	2	4	3	5	8	4	5
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	–	0	13	5	8	1	–	1	0	–	1	1
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	–	1	1	3	–	–	–	–	1	2	1
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	11	1	192	367	1,314	2,112	1,440	115	336	407	306	330	265	354
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	–	1	2	9	–	–	–	9	1	5	4
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	8	1	169	70	1,260	1,957	1,356	98	310	372	258	247	232	310
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	3	8	85	86	41	5	19	23	19	31	20	36
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	–	–	–	–	–	–	4	–	1	6	5	5
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	–	–	–	–	4	–	1	–	–	–	–	–	–	–
51	LV	LV Line	LV OH Conductor	km	–	–	19	72	491	104	42	3	9	11	7	5	4	7
52	LV	LV Cable	LV UG Cable	km	–	–	0	2	80	20	11	1	1	4	4	6	7	14
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	0	14	238	41	17	1	3	2	1	3	2	3
54	LV	Connections	OH/UG consumer service connections	No.	–	207	2,135	5,281	7,043	7,915	6,994	247	343	439	434	416	467	514
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	–	8	9	45	128	19	12	9	3	4	20	8
56	All	SCADA and communications	SCADA and communications equipment operating as a single systen	Lot	–	–	–	–	–	–	1	–	–	–	–	–	–	–
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	2	3	–	–	–	–	–	–	–
59	All	Load Control	Relays	No	–	–	–	–	–	–	–	–	–	–	–	–	–	–
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–

sch ref	Asset class	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	Concrete poles / steel structure	331	321	855	1,213	785	920	985	1,177	1,189	1,313	1,449	1,111	1,019	56	–	–	–	–	–	256	90,759	–	3
11	Wood poles	799	1,047	125	8	2	16	12	164	2	18	15	17	2	–	–	–	–	–	–	323	18,588	–	3
12	Other pole types	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
13	Subtransmission OH up to 66kV conductor	26	22	1	–	0	–	–	36	13	–	12	1	–	–	–	–	–	–	–	2	907	–	3
14	Subtransmission OH 110kV+ conductor	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
15	Subtransmission UG up to 66kV (XLPE)	2	0	–	–	–	–	–	–	2	–	0	–	0	2	–	–	–	–	–	1	11	–	3
16	Subtransmission UG up to 66kV (Oil pressurised)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
17	Subtransmission UG up to 66kV (Gas pressurised)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
18	Subtransmission UG up to 66kV (PILC)	–	0	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	0	1	–	3
19	Subtransmission UG 110kV+ (XLPE)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
20	Subtransmission UG 110kV+ (Oil pressurised)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
21	Subtransmission UG 110kV+ (Gas Pressurised)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
22	Subtransmission UG 110kV+ (PILC)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
23	Subtransmission submarine cable	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
24	Zone substations up to 66kV	1	–	–	–	–	1	1	1	1	2	8	3	2	–	–	–	–	–	–	3	58	–	3
25	Zone substations 110kV+	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
26	50/66/110kV CB (Indoor)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	50/66/110kV CB (Outdoor)	13	–	5	–	–	3	2	1	–	–	6	4	–	–	–	–	–	–	–	–	58	–	4
28	33kV Switch (Ground Mounted)	–	–	–	–	–	–	–	–	8	–	–	–	–	–	–	–	–	–	–	–	8	–	4
29	33kV Switch (Pole Mounted)	23	3	8	1	1	7	4	5	4	–	7	7	8	1	–	–	–	–	–	8	294	–	3
30	33kV RMU	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	22/33kV CB (Indoor)	–	–	–	–	–	–	–	–	7	1	–	–	–	–	–	–	–	–	–	–	20	–	4
32	22/33kV CB (Outdoor)	5	2	–	1	1	–	–	–	–	2	1	–	1	–	–	–	–	–	–	–	30	–	4
33	3.3/6.6/11/22kV CB (ground mounted)	6	–	2	–	–	20	7	13	14	9	7	5	–	–	–	–	–	–	–	–	150	–	4
34	3.3/6.6/11/22kV CB (pole mounted)	–	2	–	1	–	–	5	1	–	–	2	–	–	–	–	–	–	–	–	–	47	–	4
35	Zone Substation Transformers	–	2	1	–	3	1	6	1	2	2	4	3	–	–	–	–	–	–	–	–	62	–	4
36	Distribution OH Open Wire Conductor	72	102	76	49	51	55	37	75	34	36	11	20	8	0	–	–	–	–	–	28	6,808	–	3
37	Distribution OH Aerial Cable Conductor	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	SWER conductor	–	3	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	8	–	4
39	Distribution UG XLPE or PVC	8	4	2	2	1	4	1	3	6	3	1	15	1	0	–	–	–	–	–	8	116	–	3
40	Distribution UG PILC	3	1	1	0	1	0	–	0	–	–	0	–	–	–	–	–	–	–	–	2	37	–	3
41	Distribution Submarine Cable	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
42	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	–	1	1	–	–	–	2	3	–	4	3	5	4	–	–	–	–	–	–	–	32	–	4
43	3.3/6.6/11/22kV CB (Indoor)	–	2	–	–	–	–	–	–	–	–	1	2	9	–	–	–	–	–	–	1	15	–	3
44	3.3/6.6/11/22kV Switches and fuses (pole mounted)	433	499	546	528	456	411	351	423	341	261	291	305	309	59	–	–	–	–	–	1,035	13,798	–	3
45	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
46	3.3/6.6/11/22kV RMU	8	15	6	2	1	3	1	2	2	4	20	4	3	–	–	–	–	–	–	–	102	–	4
47	Pole Mounted Transformer	375	403	405	385	343	321	255	322	244	176	208	184	197	41	–	–	–	–	–	36	10,543	–	3
48	Ground Mounted Transformer	32	28	24	20	13	18	21	29	16	16	36	22	13	6	–	–	–	–	–	4	674	–	3
49	Voltage regulators	16	14	3	–	–	–	2	8	2	–	5	–	1	–	–	–	–	–	–	–	72	–	3
50	Ground Mounted Substation Housing	1	–	–	–	1	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	3
51	LV OH Conductor	5	6	6	5	5	4	5	5	4	5	5	5	7	0	–	–	–	–	–	5	846	–	3
52	LV UG Cable	15	6	7	5	4	4	3	2	3	1	2	3	2	0	–	–	–	–	–	4	213	–	3
53	LV OH/UG Streetlight circuit	2	1	1	3	2	1	2	0	0	0	2	1	0	–	–	–	–	–	–	12	354	–	3
54	OH/UG consumer service connections	568	683	524	421	476	358	397	326	302	277	331	329	398	35	–	–	–	–	–	179	38,039	–	3
55	Protection relays (electromechanical, solid state and numeric)	27	19	8	5	4	31	13	24	30	24	50	38	26	16	–	–	–	–	–	13	593	–	3
56	SCADA and communications equipment operating as a single systen	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	4
57	Capacitors including controls	6	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	6	–	4
58	Centralised plant	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	5	–	4
59	Relays	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
60	Cable Tunnels	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2020**
Network / Sub-network Name	

SCHEDULE 9c: REPORT ON OVERHEAD LINES AND UNDERGROUND CABLES

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

sch ref

9				
10	**Circuit length by operating voltage (at year end)**	**Overhead (km)**	**Underground (km)**	**Total circuit length (km)**
11	> 66kV	–	–	–
12	50kV & 66kV	505	–	505
13	33kV	387	12	400
14	SWER (all SWER voltages)	5	3	8
15	22kV (other than SWER)	0	1	1
16	6.6kV to 11kV (inclusive—other than SWER)	6,714	153	6,867
17	Low voltage (< 1kV)	846	213	1,059
18	**Total circuit length (for supply)**	8,457	383	8,839
19				
20	Dedicated street lighting circuit length (km)	270	84	354
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	4,574	54%
26	Remote only	806	10%
27	Rugged only	1,995	24%
28	Remote and rugged	605	7%
29	Unallocated overhead lines	2	0%
30	**Total overhead length**	8,457	100%
31			
32		**Circuit length (km)**	**(% of total circuit length)**
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,688	19%
34		**Circuit length (km)**	**(% of total overhead length)**
35	Overhead circuit requiring vegetation management	1,489	18%

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2020**

SCHEDULE 9d: REPORT ON EMBEDDED NETWORKS

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

sch ref

	Location *	Number of ICPs served	Line charge revenue ($000)
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			

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

Company Name	The Power Company Limited
For Year Ended	31 March 2020
Network / Sub-network Name	

SCHEDULE 9e: REPORT ON NETWORK DEMAND

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

sch ref				
8	**9e(i): Consumer Connections**			
9	*Number of ICPs connected in year by consumer type*			
10	*Consumer types defined by EDB**		**Number of connections (ICPs)**	
11	Domestic		295	
12	Half Hour Individual		3	
13	Non Domestic		88	
14				
15				
16	** include additional rows if needed*			
17	**Connections total**		386	
18				
19	**Distributed generation**			
20	Number of connections made in year		40	**connections**
21	Capacity of distributed generation installed in year		0.28	**MVA**
22	**9e(ii): System Demand**			
23				
24			**Demand at time of maximum coincident demand (MW)**	
25	**Maximum coincident system demand**			
26	GXP demand		127	
27	Distributed generation output at HV and above	*plus*	21	
28	**Maximum coincident system demand**		148	
29	Net transfers to (from) other EDBs at HV and above	*less*	1	
30	**Demand on system for supply to consumers' connection points**		147	
31	**Electricity volumes carried**		**Energy (GWh)**	
32	Electricity supplied from GXPs		600	
33	Electricity exports to GXPs	*less*	164	
34	Electricity supplied from distributed generation	*plus*	365	
35	Net electricity supplied to (from) other EDBs	*less*	14	
36	**Electricity entering system for supply to consumers' connection points**		787	
37	Total energy delivered to ICPs	*less*	742	
38	**Electricity losses (loss ratio)**		45	5.8%
39				
40	**Load factor**		0.61	
41	**9e(iii): Transformer Capacity**			
42			**(MVA)**	
43	Distribution transformer capacity (EDB owned)		456	
44	Distribution transformer capacity (Non-EDB owned, estimated)		46	
45	**Total distribution transformer capacity**		503	
46				
47	**Zone substation transformer capacity**		459	

Company Name	The Power Company Limited
For Year Ended	31 March 2020
Network / Sub-network Name	

SCHEDULE 10: REPORT ON NETWORK RELIABILITY

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

sch ref

8 10(i): Interruptions

sch ref	Interruptions by class	Number of interruptions
10	Class A (planned interruptions by Transpower)	1
11	Class B (planned interruptions on the network)	611
12	Class C (unplanned interruptions on the network)	629
13	Class D (unplanned interruptions by Transpower)	–
14	Class E (unplanned interruptions of EDB owned generation)	–
15	Class F (unplanned interruptions of generation owned by others)	–
16	Class G (unplanned interruptions caused by another disclosing entity)	5
17	Class H (planned interruptions caused by another disclosing entity)	–
18	Class I (interruptions caused by parties not included above)	1
19	**Total**	1,247

sch ref	Interruption restoration	≤3Hrs	>3hrs
22	Class C interruptions restored within	540	89

sch ref	SAIFI and SAIDI by class	SAIFI	SAIDI
25	Class A (planned interruptions by Transpower)	0.00	0.5
26	Class B (planned interruptions on the network)	0.51	125.0
27	Class C (unplanned interruptions on the network)	3.57	270.9
28	Class D (unplanned interruptions by Transpower)	–	–
29	Class E (unplanned interruptions of EDB owned generation)	–	–
30	Class F (unplanned interruptions of generation owned by others)	–	–
31	Class G (unplanned interruptions caused by another disclosing entity)	0.13	28.1
32	Class H (planned interruptions caused by another disclosing entity)	–	–
33	Class I (interruptions caused by parties not included above)	0.00	0.0
34	**Total**	4.21	424.5

sch ref	Normalised SAIFI and SAIDI	Normalised SAIFI	Normalised SAIDI
37	Classes B & C (interruptions on the network)	4.09	351.76

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

sch ref	Cause	SAIFI	SAIDI
42	Lightning	0.09	3.0
43	Vegetation	0.27	24.2
44	Adverse weather	0.42	47.1
45	Adverse environment	0.02	16.0
46	Third party interference	0.41	25.6
47	Wildlife	0.11	7.8
48	Human error	0.01	0.4
49	Defective equipment	1.44	117.7
50	Cause unknown	0.80	29.2

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

sch ref	Main equipment involved	SAIFI	SAIDI
55	Subtransmission lines	0.01	3.7
56	Subtransmission cables	–	–
57	Subtransmission other	0.00	0.1
58	Distribution lines (excluding LV)	0.49	118.3
69	Distribution cables (excluding LV)	0.00	0.1
60	Distribution other (excluding LV)	0.01	2.9

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

sch ref	Main equipment involved	SAIFI	SAIDI
64	Subtransmission lines	0.98	82.0
65	Subtransmission cables	–	–
66	Subtransmission other	–	–
67	Distribution lines (excluding LV)	2.41	181.7
68	Distribution cables (excluding LV)	0.09	3.5
69	Distribution other (excluding LV)	0.09	3.8

70 10(v): Fault Rate

sch ref	Main equipment involved	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
72	Subtransmission lines	27	891.9	3.03
73	Subtransmission cables	–	12.2	–
74	Subtransmission other	–		
75	Distribution lines (excluding LV)	545	6,714.0	8.12
76	Distribution cables (excluding LV)	7	154.0	4.55
77	Distribution other (excluding LV)	50		
78	**Total**	629		

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 WACC of 6.04%, which is 1.09% above the 75th percentile estimate of post-tax WACC of 4.95% and a 6.47% vanilla WACC, which is 1.10% above the 75th percentile estimate of vanilla WACC of 5.37%.

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 and the Seaward Bush to Bluff 33kv distribution lines.

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 used the 31 March 2019 figure of $385,009k as the starting point with inflationary indexing over the year to 31 March 2020 plus additions less disposals, totalling $407,982k at 31 March 2020. No items were reclassified.

Regulatory tax allowance: disclosure of permanent differences (5a(i) of Schedule 5a)

8. In the box below, provide descriptions and workings of the material items recorded in the following asterisked categories of 5a(i) of Schedule 5a-

   8.1 Income not included in regulatory profit / (loss) before tax but taxable;

   8.2 Expenditure or loss in regulatory profit / (loss) before tax but not deductible;

   8.3 Income included in regulatory profit / (loss) before tax but not taxable;

   8.4 Expenditure or loss deductible but not in regulatory profit / (loss) before tax.

Box 5: Regulatory tax allowance: permanent differences
The expenditure deductible but not in regulatory profit is the $2k 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:	$	2,175
	$	2,175
Tax Rate:		28%
Temporary Differences	$	609

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

All costs were either passed through by PowerNet as agent or were invoiced to The Power Company Limited and hence directly attributable with the exception of some Business support costs which have been apportioned using the ABAA method (no causal allocator is applicable and revenue has been used as a proxy allocator).

No items were reclassified.

Asset allocation (Schedule 5e)

11. In the box below, comment on 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.

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 and this is classified as refurbishment and renewal maintenance when the work performed is not material in relation to the overall value of the asset. No items were reclassified during the disclosure year. There was no material atypical expenditure disclosed in Schedule 6b.

Variance between forecast and actual expenditure (Schedule 7)

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

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

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

Capital Expenditure:

Consumer connection:

- Overall spend was 39% over budget
- Increased expenditure was due to a large customer application received mid-year and the continuation of previous financial year large customer connection projects due to rollover works from previous financial year that was deferred.

System Growth:

- Overall spend was 22% under budget.
- COVID-19 impacted on material delivery and construction progress. Additional delays due to delays in the design process that had a knock on effect of work in March and exacerbated by COVID 19.
- Deferment of capital works substituted with new large customer connection application received mid-year.

Asset Relocations:

- Overall spend was 59% under budget.
- Due to material delivery delays, the Fairlight Regulator relocation was deferred to 2021.

Supply Quality:

- Overall spend was 34% over budget. A large upgrade to New Vale Cole supply. Customer contributed $181,000 but this does not reflect on the WPN number, similar to Service connections votes.
- Mobile site make ready projects over budget due to additional civil costs at Kelso and Orawia.
- Supply Quality upgrades over budget as they are reactive in nature

Reliability, Safety and Environment:

- 25% over budget.
- Bluecliffs RAPS over budget to accommodate additional costs for resource consent.
- Riversdale 33kV backup connection over budget due to higher than expected transformer refurbishments costs and scope change to network design.
- Increased emphasis on earth upgrades to improve network safety.

Operational Expenditure:

Network operational expenditure was 12% under budget.

Vegetation management

- 12% under budget.
- Limited availability of contractors primary EWP vehicle

Routine and corrective maintenance and inspection:

- 11% under budget.
- Technical and Distribution reactive maintenance are below budget as they are reactive in nature. Budgets are typically set based on the average of previous year expenditure and is our best estimate. Technical and Distribution reactive maintenance is reactive in nature and repairs to fault repairs the following day/s. If the initial repair during the outage is sufficient, there will be reduction on follow up maintenance. It is reactive in nature.
- Due to increase in capital earth upgrading there was a reduction in budget for earth testing.
- Two pole structure investigations put on hold until Engineering solution complete.

Asset replacement and renewal:

- 54% under budget
- Lower defects identified during routine inspections required on subtransmission refurbishment.

System Operations and Network support 23% under budget

- Insurance Captive is not yet operational which makes up 21% of the budget.

Information relating to revenues and quantities for the disclosure year

15. In the box below provide-

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

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

The line pricing methodology revenue target of $61,681k. The total billed of $63,450k was above budget by $1,769k due to the large number of ICP's transferring to the Low User Option which has resulted in an over-recovery of variable line charges from this group. Transpower HVDC charges of $669k are also not included in the budget figure.

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 13: Commentary on network reliability for the disclosure year

The SAIDI of 424.5 minutes exceeded the Statement of Intent target of 181.48 minutes; and was higher than the 2018/19 measure of 277.5 minutes.

The SAIFI of 4.21 exceeded the Statement of Intent target of 2.83 times and was higher than the 2018/19 measure of 2.99.

In accordance with the Issues Register for Electricity and Gas Information Disclosure, issues 447 and 458, TPC has disclosed normalised SAIDI/SAIFI calculated according to the 2012 EDB ID while disclosing limits calculated according to the 2015 DPP.

TPC has disclosed a normalised SAIDI at 351.76 and normalised SAIFI at 4.09 for 2019/20.

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

The Power Company Limited has significantly reduced the amount of live line work and adjusted work practises to align with industry best practice guidelines. This reduction in live line work and adjusted work practices is reflected in increased planned and unplanned SAIDI and SAIFI. The re-introduction of live line work is being investigated for future years. External factors also influenced SAIDI and SAIFI performance negatively. Excessive winds and flooding influenced the network performance.

Due to its consumer ownership The Power Company Limited is not subject to Default Price-Quality Path regulation and had therefore not commented on performance relative to Commerce Commission quality limits.

There are inherent limitations in the ability of The Power Company Limited to collect and record the network reliability information required to be disclosed in Reports 10(i) to 10(iv). Consequently there is no independent evidence available to support the accuracy of recorded faults and control over and accuracy of installation control point ('ICP') data, included in the SAIDI and SAIFI calculations, is limited throughout the year.

Insurance cover

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

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

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

Box 15: Disclosure of amendment to previously disclosed information

No amendments were disclosed.

Box 14: Explanation of insurance cover

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

- Substations and network equipment are insured for $165.46 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.

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 (HYEFU) report released in December 2018:

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

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

SCHEDULE 15 VOLUNTARY EXPLANATORY NOTES

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

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

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

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

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

3. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information

APPENDICES

APPENDIX A:

Related Party Transactions:

Additional Information Disclosures

1. INTRODUCTION

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

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

- **The Power Company Limited's 2020 Information Disclosure**, for the year ended 31 March 2020 - 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 by incurred by The Power Company Limited (TPCL) network assets being greater than $20 million for the year ending 31 March 2020.

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, if related party opex or capex is greater than 65% of total expenditure , an independent appraiser is required to assess whether the related party transactions comply with an 'arm's length' valuation criteria.

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, Electricity Southland Limited, and the Southern Generation Limited Partnership through their wholly owned subsidiary company Last Tango Limited. PowerNet Limited has an interest in PowerNet Central Limited.

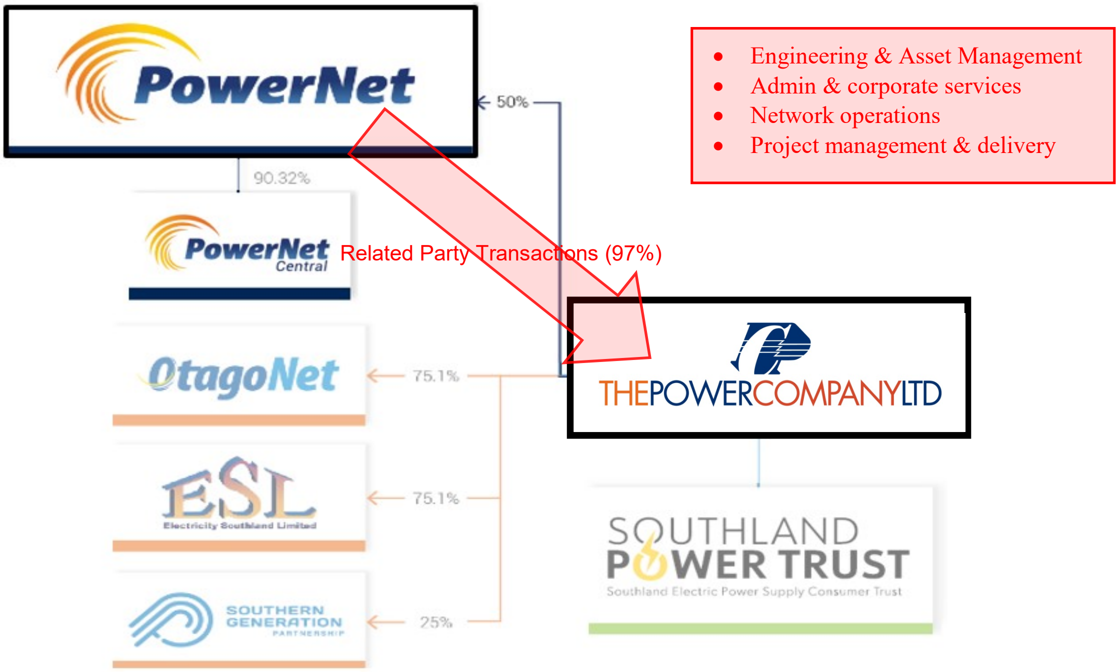
During the year ending 31 March 2020, TPCL had related party transactions with the following entities:

- Goods and services provided by – PowerNet Limited;
- Goods and services provided to – PowerNet Limited,

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



a. **PowerNet Limited**

TPCL holds a 50% shareholding in electricity network management company PowerNet Limited. 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 2020, is categorised as follows:

		($000)
Operating Expenditure:		
i.	Service interruptions and emergencies	4,477
ii.	Vegetation management	1,592
iii.	Routine and corrective maintenance and inspection	4,779
iv.	Asset replacement and renewal (Opex)	641
v.	System operations and network support	1,545
vi.	Business support	2,876
Capital Expenditure:		
vii.	Consumer connection	4,718
viii.	System growth	3,668
ix.	Asset replacement and renewal (Capex)	12,968
x.	Asset relocations	209
xi.	Quality of supply	1,240
xii.	Other reliability, safety and environment	3,543
	Total PowerNet Related Party expenditure	**42,256**

In the year to 31 March 2020, PowerNet provided 100% of the TPCL Lines Business Capital Expenditure, and 92% 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

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

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.

There were no related party transactions between OJV and TPCL during the reporting period.

Network Management Agreement ('Agency 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 identified by the Government Pricing Review and the terms of reference required investigation into the "PowerNet model" as the review looked at how other EDBs could potentially do the same.

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

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

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

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

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 an agency 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 operation 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 Officer, in line with the financial authority limits. Written cost estimates or quotes are required from Suppliers depending on the value or nature of the job to manage cost expectations.

Resourcing

Having the combined network management of TPCL, EIL, OJV and ESL, gives PowerNet a stronger position to negotiation more favourable competitive prices for goods and services, through the greater purchasing volumes and activity, than would otherwise be possible by 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 27% of the TPCL Capital project expenditure during the 2019/20 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 its regulatory 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) 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 an Agency fee, and applies an internal commercial mark-up to recover its operating costs and enable a modest commercial profit.

6. PURCHASES REQUIRED FROM A RELATED PARTY

ID Determination 2.3.12 (2)

Activities for which TPCL customers are required to use PowerNet (Related Party) in relation to electricity distribution services are:

- Fault repairs;
- Requests for a new connection to TPCL's network; and
- Removing trees or vegetation from proximity of power lines.

Fault Response and Reactive Maintenance

Under the Network Management Agreement, PowerNet is responsible for maintaining the 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/getting-connected/

Using an Independent Contractor

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

Arborist/Tree Management

PowerNet is responsible for vegetation management on the 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/

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 for an Application for Approval to Operate Machinery closer than 4m to electric power lines or have the lines de-energised.

PowerNet Arborist Services – Quotes:
Phone 03 2111899 or email trees@powernet.co.nz

Asplundh – Quotes:
Invercargill Office on 03 216 8051
Wayne, Contract Manager on 0275 533 250
enquiry@asplundh.co.nz or visit Asplundh at 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

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 Asplundh 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: Lumsden Substation 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:	Lumsden Substation Upgrade (Oreti Valley Project)
Project Date:	August 2017 – current (closed June 2020)
Project Number:	10739
Project Expenditure:	$ 4,433,000 External labour & materials $ 1,212,000 PowerNet services ---------------- $ 5,645,000 (Project Total) $ 3,651,000 (2016-2018) $ 1,693,000 (2018/19) $ 301,000 (2019/20) ---------------- $ 5,645,000
Project Classification:	System Growth (Capital Expenditure)
Project Manager:	PowerNet Ltd
Subcontractors:	Decom Ltd

The Lumsden Substation Upgrade is one of several substation assets included in the wider Oreti Valley Project (OVP), replacing and upgrading several aging assets in the rural Northern Southland area experiencing electricity consumption growth with the expansion of the dairy industry in recent years.
A review of available resources highlighted that due to the size and technical challenges with this project, and in the interest of a timely construction, it was decided to outsource the design and majority of the construction to external suppliers.

Market Testing: The majority of the Lumsden Substation Upgrade project cost was outsourced by PowerNet. A tender process was undertaken to select an external contractor for the construction, 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)

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.

Characteristics:	Requirement:
- Customer driven enquiries. - Small sized projects. - Planning is high level. - Quote provided. - Customer contribution received. - Internal Distribution staff undertake work on the Networks. - External qualified electricians are given opportunity to undertake customer work, directly engaged by customer.	❖ General amount approved in Asset Management Plan. ❖ Cost estimate - Maximo work order ❖ Payment – Purchase Order

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 House Connection (Rural Southland – October 2019)

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 House Connection (TPCL Works programme)
Completion Date:	October 2019
Project Number:	CC 348738 / 348737
Project Expenditure:	\$ 8,000 External materials \$ 5,000 PowerNet services ------------ \$ 13,000 Total Cost (2019/20)
Project Classification:	System Growth (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Distribution Team
Subcontractors:	N/a

Project CC348738 new connection application was received by the PowerNet 'Connection' team staff during mid-2019. The customer had requested a new 15kVA single phase connection to be installed from an existing pillar, for a new house.

Market Testing: PowerNet benchmarked internal labour rates favourably against similar Line Mechanic or Technician roles from other available external suppliers. Of the $5.5M capital expenditure spent on New Connections and Capacity Upgrades, 66% 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. The recent benchmarking of PowerNet business and network support services provided rated well on a cost per ICP basis, against other equivalent EDB's to TPCL.

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

Asset Replacement and Renewal projects are generally driven by internal asset condition and monitoring assessments, performed periodically by PowerNet staff on 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.

Team:	**Characteristics:**	**Requirement:**
Distribution	- Emergency fault repair work. - Network Lines repair and development. - Internal Distribution staff undertake work on Networks. - External contractors may be subcontracted by PowerNet to assist with this work.	❖ Planned - Asset Management Plan ❖ Project managed - Maximo work orders ❖ Payment – Purchase Order
Team:	**Characteristics:**	**Requirement:**
Technical Projects	- Technical specialised work. - Internal Technician staff undertake work on Networks. - External contractors with necessary skills may be subcontracted by PowerNet to assist with this work.	❖ Planned - Asset Management Plan ❖ May require Business Case approval ❖ Project managed - Maximo work order ❖ Payment – Purchase Order

EXAMPLE: Feeder Rebuild (Rural Southland – October 2019)

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

Project Name:	Feeder Rebuild Landslip Valley Road (TPCL Works Programme)
Completion Date:	October 2019
Project Number:	CC 347466
Project Expenditure:	\$ 41,000 External labour & materials \$ 82,000 PowerNet services (incl. mark-up) -------------- \$ 123,000 Total Cost (2019/20)
Regulatory Classification:	Asset Replacement & Renewal (Capital Expenditure)
Project Manager:	PowerNet Ltd
Construction:	PowerNet - Technicians Team
Subcontractors:	NA

PowerNet undertook Project CC347466 to replace poles, cross arms and insulators as they were at the end of their useful life. This work was identified through PowerNet asset inspection and condition monitoring, and was deemed essential to maintain security of supply within the area. A PowerNet Project Manager was assigned to plan and oversee the work. Consideration is given to the timing, to make sure resources are available, and to minimise the impact of a power outage to effected 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 2018-2020. The materials sourced through Corys Electrical supply agreement includes a range of contractual mechanisms to ensure efficient prices are being provided to PowerNet. The recent benchmarking of PowerNet business and network support services provided rated favourably on a cost per ICP basis, against other equivalent EDB's to TPCL.

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 2018-2020.

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.

Characteristics:	**Requirement:**
- Network vegetation management. - Some emergency fault repair work. - Internal Distribution staff undertake work on Networks. - External contractors subcontracted by PowerNet to complete this work.	❖ Planned - Asset Management Plan ❖ Project managed - Maximo work orders ❖ Payment – Purchase Order

EXAMPLE: Vegetation Management (Rural Southland – October 2019

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:	October 2019
Project Number:	CC 200709
Total Expenditure:	\$ 2,300 External labour & materials \$ 200 PowerNet services ---------- \$ 2,500 (2019/20)
Regulatory Classification:	Vegetation Management (Maintenance Expenditure)
Project Manager:	PowerNet Ltd
Subcontractors:	Asplundh Ltd

PowerNet became aware of trees growing within the permitable distance of power lines during a routine Lines inspection in the rural Southland area. Details of the location and work required (‘dismantle trees to clear 11kV powerlines’) were noted on the PowerNet Cut/Trim Notice (CTN200709), 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 on-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. 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 Maintenance
Completion Date:	March 2020
Project Number:	352544
Project Expenditure:	$ 4,000 External material $ 24,000 PowerNet services (incl. mark-up) ------------ $ 28,000 Total Cost (2019/20)
Regulatory Classification:	Technical Planned 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 manufacturers 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 2018-2020.

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 an Agency fee, which would otherwise be directly incurred by TPCL, if there was no ‘Agency Agreement’ (or NMA) in place with PowerNet.

Market Testing: Market testing the provision of business services is very difficult due to the lack of comparability available. However, the benefits of 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 2018 of PowerNet business and network support services to TPCL/EIL/OJV, against other equivalent sized EDB’s on a cost per ICP basis. The findings of the review rated 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 Amendments Determination 2017 (NZCC 33), 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 2020-2030 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 2020-2030 Asset Management Plan for TPLC network are explained below, and indicated on the Network map above where relative to a single area:

1. Incident Response – Distribution - $28.30m

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

2. Vegetation Management - $15.35m

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

3. Technical Planned Maintenance $12.86m

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

4. Distribution Inspections - $12.60 m

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

5. General Distribution Refurbishment -$5.72m

   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 - $5.55m

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

7. Distribution Earthing maintenance - $4.70m

   Routine testing of earthing assets and connections to ensure safety and functional requirements are met completed for all earths on a five yearly basis.

8. Technical Incident Reponses - $3.56m

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

9. Distribution Reactive Maintenance - $3.07m

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

10. Distribution Reactive Maintenance - $2.55m

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

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 below).
- Have a contract in place that is with PowerNet Limited through an 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 2019-2029 Asset Management Plan for TPLC network are explained below, and indicated on the Network map above where relative to a single area:

1. <u>11kV Line Replacement - $65.45m</u>

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

2. <u>Unspecified System Growth Projects - $15.61m</u>

   Scheduled for 2020 – 2035, the projects 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 large growth increases in Athol, Lumsden and Riversdale areas could result in the extension and upgrade of the subtransmission network and conversion of some affected distribution networks to 22kV.

3. <u>ABS Renewals - $13.41m</u>

   Scheduled for 2019 – 2025, when inspection indicates deterioration is sufficient enough to lose confidence in continued reliable operation and maintenance is considered uneconomic.

4. <u>Customer Connections (≤ 20kVA) - $10.43m</u>

   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.

5. Unspecified Asset Replacements - $10.42m

   Scheduled for 2027 – 2030, 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 have limited success.

   Typical identification in the short to medium term with implementation from 6 to 10.

6. Transformer Replacement - $8.85m

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

7. 22kV Upgrade Athol-Kingston - $7.02m

   Scheduled for 2021-2024, Load growth occurring in and around Kingston township is forecast to exceed the ability of the 11kV network to supply adequate voltage. There is an existing 11kV regulator at Fairlight and an additional regulator on the feeder from Athol to Kingston is not desirable. This project will mole-plough a 22kV cable from Athol to Kingston which will initially operate at 11kV. After load growth exceeds the ability of 11kV to supply Kingston, Athol substation can be converted to 22kV supply with autotransformers used to step voltage back down to 11kV at the end of completed sections. At this point the 11kV line can be upgraded to 22kV to provide an alternate supply.

8. Ground Mount Platform Transformers - $6.75m

   Scheduled for 2020 – 2035, this project will renew large platform or pole mounted distribution transformers (greater than 100 kVA) with ground mount units to minimise seismic risk. There are 145 of these transformers around TPCL's network.

9. Customer Connections (> 100kVA) - $5.79m

   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.

10. Earth Upgrades - $5.32m

    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.

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

Please Note: All of these projects -

- Are network wide (apply to entire area as shown on map below), with the exception of #7 which is pinpointed on the map below;
- Have a contract in place that is with PowerNet Limited through an agency agreement (related party), with the exception of #2 and #5;
- Are forecast to require the supply of assets/goods or services by PowerNet Limited (related party), with the exception of #2 and #5;

<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:

7. <u>22kV Upgrade Athol-Kingston - $7.02m</u>

Constraint – Unable to maintain supply voltage due to forecast load growth, timing being 1-4 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 - Unplanned	Every Year	$ 28.30m	Network Wide	Yes	Yes	Very likely	N/A
#2	Vegetation Management	Every Year	$ 15.35m	Network Wide	Yes	Yes	Very likely	N/A
#3	Technical Routine Maintenance	Every Year	$ 12.86m	Network Wide	Yes	Yes	Very likely	N/A
#4	Routine Distribution Inspections	Every Year	$ 12.60m	Network Wide	Yes	Yes	Very likely	N/A
#5	General Distribution Refurbishment	Every Year	$ 5.72m	Network Wide	Yes	Yes	Very likely	N/A
#6	Technical Routine Inspections & Checks	Every Year	$ 5.55m	Network Wide	Yes	Yes	Very likely	N/A
#7	Distribution Earthing Maintenance	Every Year	$ 4.70m	Network Wide	Yes	Yes	Very likely	N/A
#8	Incident Response - Technical - Unplanned	Every Year	$ 3.56m	Network Wide	Yes	Yes	Very likely	N/A
#9	Distribution Routine Maintenance	Every Year	$ 3.07m	Network Wide	Yes	Yes	Very likely	N/A
#10	Distribution Corrective Maintenance	Every Year	$ 2.55m	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	11kV Line Replacement	Every Year	$ 65.45m	Network Wide	Yes	Yes	Very likely	N/A
#2	Unspecified Projects System Growth	2026 - 2030	$ 15.61m	Network Wide	No	N/A	Very likely	N/A
#3	ABS renewals	Every Year	$ 13.41m	Network Wide	Yes	Yes	Very likely	N/A
#4	Customer Connections (≤ 20kVA)	Every Year	$ 10.43m	Network Wide	Yes	Yes	Very likely	N/A
#5	Unspecified Asset Replacements	2027 - 2030	$ 10.42m	Network Wide	No	N/A	Very likely	N/A
#6	Transformer Replacement	Every year	$ 8.85m	Network Wide	Yes	Yes	Very likely	N/A
#7	22kV Upgrade Athol - Kingston	Every Year	$ 7.02m	#7	Yes	Yes	Very likely	N/A
#8	Ground Mount Platform Transformers	2020 - 2035	$ 6.75m	Network Wide	Yes	Yes	Very likely	N/A
#9	Customer Connections (≥ 100kVA)	Every Year	$ 5.79m	Network Wide	Yes	Yes	Very likely	N/A
#10	Earth Upgrades	Every Year	$ 5.32m	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).

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 as amended by the Information Disclosure exemption: Disclosure and auditing of reliability information within schedule 10, issued by the Commerce Commission on 9 April 2020 (the 'Information Disclosure Determination, as amended') for the disclosure year ended 31 March 2020 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 Information Disclosure Determination, as amended, and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 ('the Input Methodologies Determination'); and

- whether the steps taken by the Company, as specified under the "Summary of steps and analysis undertaken by the Company to test 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 2020 complies, in all material respects, with the Information Disclosure Determination, as amended and the Input Methodologies Determination; and

- the steps undertaken by the Company, as specified under the "Summary of steps and analysis undertaken by the Company to test 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 valuation requirements as set out in the Information Disclosure Determination, as amended and the Input Methodologies Determination for the year ended 31 March 2020.

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

Our Independence and Quality Control

We are independent of the Company in accordance with Professional and Ethical Standard 1 *International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand)* (PES 1) issued by the New Zealand Auditing and Assurance Standards Board and the *International Code of Ethics for Professional Accountants (including International Independence Standards)* issued by the International Ethics Standards Board for Accountants (IESBA Code), and we have fulfilled our other ethical responsibilities in accordance with these requirements.

The firm applies Professional and Ethical Standard 3 (Amended) and accordingly 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 Company. Other than our role as financial statement auditors our firm carries out other services for the Company in the areas of compliance with regulatory requirements of the Commerce Act 1986 and the provision of regulatory advisory services. The provision of these other services has not impaired our independence as Appraiser of the Company.

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, as amended and the Input Methodologies Determination.

Quantitative materiality level was determined as 2% of total related party transactions. Qualitative factors were also considered when assessing the arm's length valuation rules on related party transactions.

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 related party information as a whole.

Key assumptions we made in carrying out our procedures

In carrying out our procedures 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 2020 in relation to our work as the independent appraiser for the disclosure year ended 31 March 2020.

Basis used for sampling of related party transactions

We obtained the Company's assessment of their compliance with the relevant related party valuation requirements in the Information Disclosure Determination, as amended and the 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, as amended and the 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, as amended, and disclosed these in Appendix A to the 2020 Information Disclosure Schedules as prepared and published under the Information Disclosure Determination, as amended.

During the year related party transactions occurred with PowerNet Limited (50% shareholding) (PowerNet).

- PowerNet provides network management services to The Power Company (TPC), OtagoNet Joint Venture (OJV), Electricity Invercargill Ltd (EIL) and Electricity Southland Ltd (ESL), 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 2020:

Operating Expenditure (opex):		***$'000***
i.	Service interruption and emergencies	4,477
ii.	Vegetation management	1,592
iii.	Routine & corrective maintenance	4,779
iv.	Asset replacement and renewal	641
v.	System operations & network support	1,545
vi.	Business support	2,876
Total opex		**15,910**

Capital Expenditure (capex):

vii.	Consumer connection	4,718
viii.	System growth	3,668
ix.	Asset replacement and renewal	12,968
x.	Asset relocations	209
xi.	Quality of supply	1,240
xii.	Other reliability, safety and environment	3,543
Total capex		**26,346**
Total PowerNet Related Party Expenditure		**42,256**

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 2020 Information Disclosure schedules to the audited financial statements for the year ended 31 March 2020 and to the accounting records, investigating any differences and determining whether any such differences are justified; and
- Applying our understanding of the business structure against the related party definition in 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

TPC incurs 100% of its capex and the majority of its operating costs for its electricity distribution business from PowerNet, in accordance with the explicit terms and conditions of the PowerNet Network Management Agreement (NMA).

While TPC owns the network assets, under the NMA PowerNet manage the network assets, carry out an agreed capital works programme, have the exclusive right to provide line function services and provide the business administration services on behalf of TPC.

PowerNet was established in 1994 to extract operational efficiencies from the merger of field work management, asset management and office based functions performed by TPC and Electricity Invercargill Limited (EIL). In 1993, there were two autonomous lines companies in Southland (TPC and EIL). Each had separate staff, management and Board of Directors, and each had a different ownership structure. We understand the 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 we understand a single lines company was not considered possible, however a single network management entity was a viable option.

PowerNet increased its operations to include OJV and ESL, and therefore extended its scale and opportunity for efficiency. Part of the policy intent of the new related party rules is to address concerns that related parties may be inefficient which may cause the Company to overcharge consumers. TPC notes that the intent of the PowerNet Group structure and NMA was to generate cost efficiencies and savings through economy of scale, improve network reliability and secure qualified staff to efficiently maintain the network assets within the region.

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:

- Approval of the NMA and annual business plan by the TPC Board;
- A focus on ensuring efficient cost and effective management of the network with regular measurement of performance and monitoring in the monthly board reports;
- 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, ESL 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 2020 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 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 capex and 92% of TPC's opex during the year ended 31 March 2020. Whilst PowerNet performs the majority of TPC's capex and opex work, we note that 42% of the costs relate to external materials and labour obtained at 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 an unrelated PowerNet customers and confirmed the internal labour rates and commercial mark-up to that 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 common Directors across the Boards with the PowerNet Board represented by a 50:50 composition from the TPC and EIL 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 interest*

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 TPC pursues 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 independent and objective 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

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 and equipment 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/process as 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 and material (Opex - $3m and Capex - $14.8m)

- 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 - $1.3m and Capex - $3.3m)

- Obtained the NMA and minutes of TPC board meetings and noted approval by the TPC Board of the cost allocation methods;
- Obtained all of the PowerNet NMAs and note consistent terms and mark-up rates are applied to PowerNet's EDB customers; and
- Obtained an independent advisor report prepared on the reasonableness of the allocation of costs between the PowerNet EDB customers. We note the report supports the transparent and consistent application of cost allocation between PowerNet's EDB customers.
- Obtained PowerNet's contracting mark-up rates for a sample of external customer projects undertaken during the year and note mark-up rates applied to PowerNet's EDB customers are at or below those market rates charged to external customers.
- Obtained the capital project indirect labour allocation analysis and tested a sample of the inputs to supporting documentation and verified the nature of tasks performed and estimated FTE allocation through interviews with a sample of employees.

Internal labour & equipment charges (Opex - $7.3m and Capex - $8m)

- Obtained a copy of the independent electrical engineer's report on the 2019/20 works programme review which assessed the forecast spend of a sample of projects for prudency and efficiency;
- 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 - $4.4m)

- 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 FY19/20 and note approval by the TPC board of the basis for allocation of the agency fee;
- Obtained an independent advisor report prepared on the reasonableness of the allocation of costs between the PowerNet EDB customers. We note the report supports the transparent and consistent application of cost allocation between PowerNet's EDB customers;
- 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). These costs have also reduced over the past five years, whereas industry and peer group averaged costs per ICP have remained relatively constant, in nominal terms.

Director's Responsibilities

The Directors are responsible on behalf of the Company for:

- compliance with the Information Disclosure Determination, as amended and the valuation of related party transactions in accordance with the Information Disclosure Determination, as amended 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, as amended. In preparing the report we are required to express an opinion on whether, for the disclosure year ended 31 March 2020, the basis for valuation of related party transactions complies, in all material respects, with the Information Disclosure Determination, as amended 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, as amended 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, as amended 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, as amended and the Input Methodologies 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 with compliance requirements may occur and not be detected.

A reasonable assurance engagement for the disclosure year ended 31 March 2020 does not provide assurance on whether compliance with the relevant related party valuation requirements of the Information Disclosure Determination, as amended and the Input Methodologies Determination will continue in the future.

Who we report to

This report has been prepared for the Directors and the Commerce Commission in accordance with clause 2.8.4 of the Information Disclosure Determination, as amended 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 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 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.

Chartered Accountants
27 August 2020

Christchurch, New Zealand

Independent Auditor's Report

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

Assurance Report Pursuant to Electricity Distribution Information Disclosure Determination 2012, as amended

We have completed our reasonable assurance engagement in respect of the compliance of The Power Company Limited (the 'Company') with the Electricity Distribution Information Disclosure Determination 2012 as amended by the Information Disclosure exemption: Disclosure and auditing of reliability information within schedule 10, issued by the Commerce Commission on 9 April 2020 (the 'Information Disclosure Determination, as amended') for the disclosure year ended 31 March 2020 where we are required to opine on:

- whether the Company has complied, in all material respects, with the Information Disclosure Determination, as amended, 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 Information Disclosure Determination, as amended, and clauses 2.2.11(1)(g) and 2.2.11(5) of the Electricity Distribution Services Input Methodologies Determination 2012 ('the Input Methodologies Determination').

Qualified Opinion

In our opinion, except for the matters described in the *Basis for Qualified Opinion* section of our report:

- As far as appears from our examination, proper records have been kept by the Company to enable the complete and accurate compilation of the Disclosure Information;

- 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 Company has complied, in all material respects, with the Information Disclosure Determination, as amended in preparing the Disclosure Information; and

- The basis for valuation of related-party transactions complies, in all material respects, with the Information Disclosure Determination, as amended and the Input Methodologies Determination.

Basis for Qualified Opinion on Schedules 10(i) to 10(iv)

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

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

We conducted our engagement in accordance with 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 Information Disclosure Determination, as amended and Input Methodologies Determination in the preparation of the Schedules for the year ended 31 March 2020.

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

Our Independence and Quality Control

We are independent of the Company in accordance with Professional and Ethical Standard 1 *International Code of Ethics for Assurance Practitioners (including International Independence Standards) (New Zealand)* (PES 1) issued by the New Zealand Auditing and Assurance Standards Board and the *International Code of Ethics for Professional Accountants (including International Independence Standards)* issued by the International Ethics Standards Board for Accountants (IESBA Code), and we have fulfilled our other ethical responsibilities in accordance with these requirements.

The firm applies Professional and Ethical Standard 3 (Amended) and accordingly 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 Company. Our firm carries out other services for the Company in the areas of compliance with regulatory requirements of the Commerce Act 1986, financial statement audit and the provision of regulatory advisory services. The provision of these other services has not impaired our independence as auditor of the Company.

Our audit approach

Overview

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, as amended and Input Methodologies Determination.

Quantitative materiality levels are determined for individual schedules included in the Disclosure Information based on the nature of the information set out in the schedules.

Profit based schedules –10% of Regulatory profit before tax
Asset based schedules – 3% of Regulatory asset base
Performance based schedules – 5% of non-financial measures
Related party transactions – 2% of total related party transactions. Qualitative factors were also considered when assessing the arm's length valuation rules on related party transactions.

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 Information Disclosure Determination, as amended in the preparation of the Disclosure Information for the year ended 31 March 2020, and whether the basis for valuation of related party transactions complies, in all material respects, with the Information Disclosure Determination, as amended and the Input Methodologies 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 determine 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 Company's electricity distribution assets. These are valued using an indexed historic cost methodology prescribed by the Information Disclosure Determination, as amended. It is a measure which is used widely and is key to measuring the Company's return on investment and therefore important when monitoring financial performance or setting electricity distribution prices. The RAB inputs, as set out in the Input Methodologies, are similar to those used in the measurement of fixed assets in the financial statements, however, there are a number of different requirements and complexities which require careful consideration. Due to the importance of the RAB within the regulatory regime, the incentives to overstate the RAB value, and complexities within the regulations, we have considered it to be a key area of focus.	We have obtained an understanding of the compliance requirements relevant to the RAB as set out in the Information Disclosure Determination, as amended and the Input Methodologies Determination. We have performed the following procedures: *Assets commissioned* • We reconciled the assets commissioned as per the regulatory fixed asset register to the asset additions disclosed in the audited annual financial statements, and investigated any reconciling items; • We inspected the assets commissioned during the period, as per the regulatory fixed asset register, to identify any specific cost or asset type exclusions, as set out in the Information Disclosure Determination, which are required to be removed from the RAB; • We tested a sample of assets commissioned during the disclosure period for appropriate asset category classification; *Depreciation* • We compared the standard asset lives by asset category to those set out in the Input Methodologies Determination;

Key assurance matter	How our procedures addressed the key assurance matter
	• We verified the spreadsheet formula utilised to calculate regulatory depreciation expense is in line with Input Methodologies Determination clause 2.2.5; *Revaluation* • We recalculated the revaluation rate set out in the Input Methodologies Determination using the relevant Consumer Price Index indices taken from the Statistics New Zealand website; • We tested the mathematical accuracy of the revaluation calculation performed by management; *Disposals* • We inspected the asset disposals within the accounting fixed asset register to ensure disposals in the RAB meet the definition of a disposal per the Input Methodologies Determination; We have no matters to report from undertaking those procedures.
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 Information Disclosure Determination, as amended and the Input Methodologies Determination are set out in Appendix A. The Information Disclosure Determination and the Input Methodologies Determination require the Company to value its transactions with related parties, disclosed in Schedule 5b, in accordance with the principles-based approach to the arm's length valuation rule. This rule states that the value of goods or services acquired from a related party cannot be greater than if it had been acquired under the terms of an arm's length transaction with an unrelated party, nor may it exceed the actual cost to the related party. A sale or supply to a related party cannot be valued at an amount less than if it had been sold or supplied under the terms of an arm's-length transaction with an unrelated party. Arm's-length valuation, as defined in the Input Methodologies 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	We have obtained an understanding of the compliance requirements relevant to related party transactions as set out in the Information Disclosure Determination, as amended, and the Input Methodologies 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. We have performed the following procedures over Schedule 5(b) and Appendix A. *Completeness and accuracy of related party relationships and transactions* We have tested the completeness and accuracy of the related party relationships and transactions by: • Agreeing the disclosures within Schedule 5(b) to the audited financial statements for the year ended 31 March 2020 and to the accounting records, investigating any differences and determining whether any such differences are justified; and • Applying our understanding of the business structure against the related party definition in Input Methodologies Determination clause 1.1.4(2)(b) to assess management's identification of any "unregulated parts" of the entity. *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

Key assurance matter	How our procedures addressed the key assurance matter
acting independently of each other and pursuing their own best interests. The Company is required to use an objective and independent measure to demonstrate compliance with the arm's-length principle. In the absence of an active market for similar transactions, assigning an objective arm's length value to a related party transaction is difficult and requires significant judgement. We have identified related party transactions at arm's-length as a key audit matter due to the judgement involved.	compliance with the disclosed procurement policy and practices. *Arm's length valuation rule* We obtained the Company's assessment of the available independent and objective measures used in supporting the arm's length valuation principle and performed the following procedures: • Re-performed the calculations and agreed key inputs and assumptions to supporting documentation; • Where benchmarking or other market information was used as independent and objective measures we assessed whether the related party transaction values fell within an acceptable range. Qualitative factors were considered in determining the appropriate acceptable range. We have no matters to report from undertaking those procedures.

Director's Responsibilities

The Directors are responsible on behalf of the Company for

- compliance with the Information Disclosure Determination, as amended and the valuation of related party transactions in accordance with the Information Disclosure Determination, as amended 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.

Auditors' Responsibilities

Our responsibility is to express an opinion on whether the Company has complied, in all material respects, with the Information Disclosure Determination, as amended in the preparation of the Disclosure Information for the disclosure year ended 31 March 2020 and on whether the basis for valuation of related party transactions complies, in all material respects, with the Information Disclosure Determination, as amended and the Input Methodologies Determination.

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 about whether the Company has complied in all material respects with the Information Disclosure Determination, as amended in the preparation of the Disclosure Information for the disclosure year ended 31 March 2020, and whether the basis for valuation of related party transactions complies, in all material respects, with the Information Disclosure Determination, as amended and the Input Methodologies Determination.

An assurance engagement to report on the Company's compliance with the Information Disclosure Determination, as amended and the Input Methodologies Determination involves performing procedures to obtain evidence about the compliance activity and controls implemented to meet the requirements of the Information Disclosure Determination, as amended 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 requirements of the Information Disclosure Determination, as amended and the Input Methodologies 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 with compliance requirements may occur and not be detected.

A reasonable assurance engagement for the disclosure year ended 31 March 2020 does not provide assurance on whether compliance with the requirements of the Information Disclosure Determination, as amended and the Input Methodologies Determination will continue in the future.

Who we report to

This report has been prepared for the Directors and the Commerce Commission in accordance with clause 2.8.1(1) of the Information Disclosure Determination, as amended 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 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
27 August 2020

Christchurch, New Zealand

5. Schedule 18: Certification for Year-End Disclosures

Clause 2.9.2

We, Douglas William Fraser and Donald Owen Nicolson, 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.]

Douglas William Fraser **Donald Owen Nicolson**

26 August 2020

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 9 April 2020 that has removed the auditor report requirements relating to the treatment of successive interruptions for reporting SAIDI, SAIFI, and interruptions, because of potential inconsistencies in treatment approaches across the industry.

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