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 2014

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, issued 1 October 2012,
- The Electricity Distribution Services Input Methodologies Determination 2012, issued 15 November 2012,

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 2014**

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.

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**	19,724	390	99,874	1,532	33,240
10	Network	12,790	253	64,761	994	21,554
11	Non-network	6,934	137	35,112	539	11,686
12						
13	**Expenditure on assets**	32,884	650	166,509	2,555	55,418
14	Network	32,884	650	166,509	2,555	55,418
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**	78,971	1,561
20	Standard consumer line charge revenue	85,077	1,388
21	Non-standard consumer line charge revenue	50,156	1,500,417
22			

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

sch ref			
24			
25	Demand density	16	*Maximum coincident system demand per km circuit length (for supply) (kW/km)*
26	Volume density	78	*Total energy delivered to ICPs per km circuit length (for supply) (MWh/km)*
27	Connection point density	4	*Average number of ICPs per km circuit length (for supply) (ICPs/km)*
28	Energy intensity	19,769	*Total energy delivered to ICPs per Average number of ICPs (kWh/ICP)*
29			
30			

31 **1(iv): Composition of regulatory income**

sch ref		($000)	% of revenue
32			
33	Operational expenditure	13,498	25.04%
34	Pass-through and recoverable costs	15,972	29.64%
35	Total depreciation	11,626	21.57%
36	Total revaluation	4,671	8.67%
37	Regulatory tax allowance	1,810	3.36%
38	Regulatory profit/loss	15,658	29.05%
39	**Total regulatory income**	53,893	
40			

41 **1(v): Reliability**

sch ref		Interruptions per 100 circuit km
42		
43	Interruption rate	13.86

Company Name	The Power Company Limited
For Year Ended	31 March 2014

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

sch ref	2(i): Return on Investment	CY-2	CY-1	Current Year CY
8		31 Mar 12	31 Mar 13	31 Mar 14
9	**Post tax WACC**	%	%	%
10	**ROI—comparable to a post tax WACC**	3.72%	3.01%	3.91%
11				
12	**Mid-point estimate of post tax WACC**	6.40%	5.85%	5.43%
13	25th percentile estimate	5.68%	5.13%	4.71%
14	75th percentile estimate	7.11%	6.56%	6.14%
15				
16				
17	**Vanilla WACC**			
18	**ROI—comparable to a vanilla WACC**	4.54%	3.78%	4.59%
19				
20	**Mid-point estimate of vanilla WACC**	7.22%	6.62%	6.11%
21	25th percentile estimate	6.51%	5.91%	5.39%
22	75th percentile estimate	7.94%	7.34%	6.83%
23				

sch ref		2(ii): Information Supporting the ROI		($000)
25				
26		Total opening RAB value	306,568	
27	*plus*	Opening deferred tax	(6,462)	
28		Opening RIV		300,106
29				
30		Operating surplus / (deficit)	24,423	
31	*less*	Regulatory tax allowance	1,810	
32	*less*	Assets commissioned	17,755	
33	*plus*	Asset disposals	751	
34		**Notional net cash flows**		5,610
35				
36		Total closing RAB value	315,316	
37	*less*	Adjustment resulting from asset allocation	(1,300)	
38	*less*	Lost and found assets adjustment	-	
39	*plus*	Closing deferred tax	(8,458)	
40		**Closing RIV**		308,158
41				
42		**ROI—comparable to a vanilla WACC**		4.59%
43				
44		Leverage (%)		44%
45		Cost of debt assumption (%)		5.56%
46		Corporate tax rate (%)		28%
47				
48		**ROI—comparable to a post tax WACC**		3.91%

sch ref	2(iii): Information Supporting the Monthly ROI						
57							
58	**Cash flows**				($000)		
59		Total regulatory income	Expenses	Tax payments	Assets commissioned	Asset disposals	Notional net cash flows
60	April						-
61	May						-
62	June						-
63	July						-
64	August						-
65	September						-
66	October						-
67	November						-
68	December						-
69	January						-
70	February						-
71	March						-
72	**Total**	-	-	-	-	-	-
73							

sch ref		Opening / closing RAB	Adjustment resulting from asset allocation	Lost and found assets adjustment	Opening / closing deferred tax	Revenue related working capital	Total
75	Monthly ROI - opening RIV	306,568			(6,462)		300,106
76							
77	Monthly ROI -closing RIV	315,316	(1,300)	-	(8,458)	-	308,158
78	Monthly ROI -closing RIV less term credit spread differential allowance						308,158
79	**Monthly ROI—comparable to a vanilla WACC**						N/A
80							
81	**Monthly ROI—comparable to a post-tax WACC**						N/A
82							

sch ref	2(iv): Year-End ROI Rates for Comparison Purposes	
84		
85	**Year-end ROI—comparable to a vanilla WACC**	5.07%
86		
87	**Year-end ROI—comparable to a post-tax WACC**	4.38%
88		

89 ** 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.*

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2014**

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 3(i), 3(iv) and 3(v) and must provide explanatory comment on their regulatory profit in Schedule 14 (Mandatory Explanatory Notes).
Non-exempt EDBs must also complete sections 3(ii) and 3(iii).
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**	**($000)**
8		**Income**	
9		Line charge revenue	54,040
10	*plus*	Gains / (losses) on asset disposals	(665)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	518
12			
13		**Total regulatory income**	53,893
14		**Expenses**	
15	*less*	Operational expenditure	13,498
17	*less*	Pass-through and recoverable costs	15,972
18			
19		**Operating surplus / (deficit)**	24,423
20			
21	*less*	Total depreciation	11,626
22			
23	*plus*	Total revaluation	4,671
24			
25		**Regulatory profit / (loss) before tax & term credit spread differential allowance**	17,468
26			
27	*less*	Term credit spread differential allowance	-
28			
29		**Regulatory profit / (loss) before tax**	17,468
30			
31	*less*	Regulatory tax allowance	1,810
32			
33		**Regulatory profit / (loss)**	15,658
34			

sch ref			
35	**3(ii): Pass-Through and Recoverable Costs**		**($000)**
36	**Pass-through costs**		
37	Rates	153	
38	Commerce Act levies	19	
	Electricity Authority levies	102	
40	Other specified pass-through costs	-	
41	**Recoverable costs**		
42	Net recoverable costs allowed under incremental rolling incentive scheme	-	
43	Non-exempt EDB electricity lines service charge payable to Transpower	13,982	
44	Transpower new investment contract charges	197	
45	System operator services	-	
46	Avoided transmission charge	1,518	
47	Input Methodology claw-back	-	
48	Recoverable customised price-quality path costs	-	
49	**Pass-through and recoverable costs**		15,972

sch ref				
57	**3(iii): Incremental Rolling Incentive Scheme**		**($000)**	
58			**CY-1**	**CY**
59			**31 March 2013**	**31 March 2014**
60	Allowed controllable opex			
61	Actual controllable opex			
62				
63	Incremental change in year			
64				
65			**Previous years' incremental change**	**Previous years' incremental change adjusted for inflation**
66	CY-5	31 Mar 09		
67	CY-4	31 Mar 10		
68	CY-3	31 Mar 11		
69	CY-2	31 Mar 12		
70	CY-1	31 Mar 13		
71	**Net incremental rolling incentive scheme**			-
72				
73	**Net recoverable costs allowed under incremental rolling incentive scheme**			-

sch ref			
74	**3(iv): Merger and Acquisition Expenditure**		
75	Merger and acquisition expenses		-
76			
77	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)		
78	**3(v): Other Disclosures**		
79	Self-insurance allowance	-	

Company Name	The Power Company Limited
For Year Ended	31 March 2014

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

			RAB	RAB	RAB	RAB	RAB
7	**4(i): Regulatory Asset Base Value (Rolled Forward)**						
8		for year ended	31 Mar 10	31 Mar 11	31 Mar 12	31 Mar 13	31 Mar 14
9			($000)	($000)	($000)	($000)	($000)
10	**Total opening RAB value**		276,178	293,425	297,839	299,707	306,568
11							
12	*less* **Total depreciation**		11,584	12,350	12,296	12,583	11,626
13							
14	*plus* **Total revaluations**		5,626	7,065	4,656	2,564	4,671
15							
16	*plus* **Assets commissioned**		23,914	10,323	10,306	17,357	17,755
17							
18	*less* **Asset disposals**		709	624	798	477	751
19							
20	*plus* **Lost and found assets adjustment**		-	-	-	-	-
21							
22	*plus* **Adjustment resulting from asset allocation**		-	-	-	-	(1,300)
23							
24	**Total closing RAB value**		293,425	297,839	299,707	306,568	315,316
25							

			Unallocated RAB *		RAB	
26	**4(ii): Unallocated Regulatory Asset Base**					
28			($000)	($000)	($000)	($000)
29		**Total opening RAB value**		306,618		306,568
30	*less*					
31		**Total depreciation**		11,626		11,626
32	*plus*					
33		**Total revaluations**		4,672		4,671
34	*plus*					
35		Assets commissioned (other than below)	-		-	
36		Assets acquired from a regulated supplier	-		-	
37		Assets acquired from a related party	17,755		17,755	
38		**Assets commissioned**		17,755		17,755
39	*less*					
40		Asset disposals (other than below)	2,074		723	
41		Asset disposals to a regulated supplier	-		-	
42		Asset disposals to a related party	28		28	
43		**Asset disposals**		2,102		751
44						
45	*plus*	**Lost and found assets adjustment**		-		-
46						
47	*plus*	**Adjustment resulting from asset allocation**				(1,300)
48						
49		**Total closing RAB value**		315,316		315,316

** 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 non-regulated services. The RAB value represents the value of these assets after applying this cost allocation. Neither value includes works under construction.*

50

			Unallocated RAB *		RAB	
58	**4(iii): Calculation of Revaluation Rate and Revaluation of Assets**					
59						
60		CPI_4				1,192
61		CPI_4^{-4}				1,174
62		Revaluation rate (%)				1.53%
63						
65			($000)	($000)	($000)	($000)
66		Total opening RAB value	306,618		306,568	
67	*less*	Opening RAB value of fully depreciated, disposed and lost assets	1,932		1,932	
68						
69		Total opening RAB value subject to revaluation	304,686		304,636	
70		**Total revaluations**		4,672		4,671
71						

Row				Unallocated works under construction		Allocated works under construction	
72	**4(iv): Roll Forward of Works Under Construction**						
73							
74		**Works under construction—preceding disclosure year**			12,733		12,733
75	*plus*	Capital expenditure		20,593		20,593	
76	*less*	Assets commissioned		17,755		17,755	
77	*plus*	Adjustment resulting from asset allocation				-	
78		**Works under construction - current disclosure year**			15,571		15,571
79							
80		Highest rate of capitalised finance applied					-

Row				Unallocated RAB *		RAB	
88	**4(v): Regulatory Depreciation**						
89							
90				($000)	($000)	($000)	($000)
91		Depreciation - standard		11,626		11,626	
92		Depreciation - no standard life assets		-		-	
93		Depreciation - modified life assets		-		-	
94		Depreciation - alternative depreciation in accordance with CPP		-		-	
95		**Total depreciation**			11,626		11,626
96							

97 4(vi): Disclosure of Changes to Depreciation Profiles

($000 unless otherwise specified)

Row	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
98					
99					
100					
101					
102					
103					
104					
105					
106					

** include additional rows if needed*

107 4(vii): Disclosure by Asset Category

108 ($000 unless otherwise specified)

Row			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
109												
110		**Total opening RAB value**	42,345	1,252	53,657	125,213	18,721	51,826	6,311	5,953	1,290	306,568
111	*less*	Total depreciation	1,397	32	2,102	5,088	559	1,848	374	223	2	11,626
112	*plus*	Total revaluations	648	19	816	1,915	287	781	95	91	20	4,671
113	*plus*	Assets commissioned	2,281	-	7,787	4,082	193	2,162	806	445	-	17,755
114	*less*	Asset disposals	-	-	130	-	-	597	24	-	-	751
115	*plus*	Lost and found assets adjustment	-	-	-	-	-	-	-	-	-	-
116	*plus*	Adjustment resulting from asset allocation	-	-	-	-	-	-	-	-	(1,300)	(1,300)
117	*plus*	Asset category transfers	-	-	-	-	-	-	-	-	-	-
118		**Total closing RAB value**	43,877	1,240	60,028	126,122	18,641	52,324	6,812	6,266	7	315,316
119												
120		**Asset Life**										
121		Weighted average remaining asset life	34.2	38.5	32.7	24.5	46.2	27.8	35.0	16.5	-	(years)
122		Weighted average expected total asset life	54.6	46.7	47.6	57.2	63.1	46.9	44.0	31.0	-	(years)

Company Name: The Power Company Limited
For Year Ended: 31 March 2014

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**			17,468
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	7,261		
13		Amortisation of revaluations	699		
14					7,960
15					
16	*less*	Income included in regulatory profit / (loss) before tax but not taxable	4,671	*	
17		Discretionary discounts and consumer rebates	6,950		
18		Expenditure or loss deductible but not in regulatory profit / (loss) before tax**	1	*	
19		Notional deductible interest	7,342		
20					18,964
21					
22		**Regulatory taxable income**			6,465
23					
24	*less*	Utilised tax losses	-		
25		Regulatory net taxable income			6,465
26					
27		Corporate tax rate (%)	28%		
28		**Regulatory tax allowance**			1,810
29					
30		* Workings to be provided in Schedule 14			
31		** Excluding discretionary discounts and consumer rebates			
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	174,261		
37		Amortisation of initial differences in asset values	7,261		
38		Adjustment for unamortised initial differences in assets acquired	-		
39		Adjustment for unamortised initial differences in assets disposed	536		
40		Closing unamortised initial differences in asset values			166,464
41					
42		Opening weighted average remaining asset life (years)			24
43		**5a(iv): Amortisation of Revaluations**			**($000)**
44					
45		Opening Sum of RAB values without revaluations	288,076		
46					
47		Adjusted depreciation	10,927		
48		Total depreciation	11,626		
49		Amortisation of revaluations			699

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	(6,462)	
plus	Tax effect of adjusted depreciation	3,060	
less	Tax effect of total tax depreciation	3,010	
plus	Tax effect of other temporary differences*	202	
less	Tax effect of amortisation of initial differences in asset values	2,033	
plus	Deferred tax balance relating to assets acquired in the disclosure year	-	
less	Deferred tax balance relating to assets disposed in the disclosure year	150	
plus	Deferred tax cost allocation adjustment	(64)	
	Closing deferred tax		(8,458)

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	103,131	
less	Tax depreciation	10,751	
plus	Regulatory tax asset value of assets commissioned	18,854	
less	Regulatory tax asset value of asset disposals	215	
plus	Lost and found assets adjustment	-	
plus	Other adjustments to the RAB tax value	(1,073)	
	Closing sum of regulatory tax asset values		109,946

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2014**

SCHEDULE 5b: REPORT ON RELATED PARTY TRANSACTIONS

This schedule provides information on the valuation of related party transactions, in accordance with section 2.3.6 and 2.3.7 of the ID 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

sch ref		($000)
7	**5b(i): Summary—Related Party Transactions**	
8	Total regulatory income	-
9	Operational expenditure	12,479
10	Capital expenditure	22,503
11	Market value of asset disposals	34
12	Other related party transactions	-

sch ref	Name of related party	Related party relationship
13	**5b(ii): Entities Involved in Related Party Transactions**	
14	**Name of related party**	**Related party relationship**
15	PowerNet Limited	50% shareholding
16		
17		
18		
19		
20	** include additional rows if needed*	

sch ref	Name of related party	Related party transaction type	Description of transaction	Value of transaction ($000)	Basis for determining value
21	**5b(iii): Related Party Transactions**				
22	**Name of related party**	**Related party transaction type**	**Description of transaction**	**Value of transaction ($000)**	**Basis for determining value**
23	PowerNet	Capex	Builds network capex on behalf of line business	22,503	Cost and mark-up, price paid
24	PowerNet	Opex	Completes maintenance on behalf of lines business	8,752	Directors' Certificates
25	PowerNet	Sales	Purchase assets	34	Fair Value
26	PowerNet	Opex	Undertakes overhead activities on behalf of lines business	3,727	Directors' Certificates
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					

** include additional rows if needed*

Company Name	The Power Company Limited
For Year Ended	31 March 2014

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	Cost of executing an interest rate swap	Debt issue cost readjustment
11										
12										
13										
14										
15										
16	** include additional rows if needed*						-	-	-	-

17

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

19

sch ref			
20	**Gross term credit spread differential**		-
21			
22	Total book value of interest bearing debt		
23	Leverage	44%	
24	Average opening and closing RAB values		
25	**Attribution Rate (%)**		-
26			
27	**Term credit spread differential allowance**		-

Company Name: The Power Company Limited
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SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref						
7	**5d(i): Operating Cost Allocations**					
8				Value allocated ($000s)		
9		Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
10	**Service interruptions and emergencies**					
11	Directly attributable		2,920			
12	Not directly attributable		-		-	
13	**Total attributable to regulated service**		2,920			
14	**Vegetation management**					
15	Directly attributable		1,379			
16	Not directly attributable		-		-	
17	**Total attributable to regulated service**		1,379			
18	**Routine and corrective maintenance and inspection**					
19	Directly attributable		3,431			
20	Not directly attributable		-		-	
21	**Total attributable to regulated service**		3,431			
22	**Asset replacement and renewal**					
23	Directly attributable		1,022			
24	Not directly attributable		-		-	
25	**Total attributable to regulated service**		1,022			
26	**System operations and network support**					
27	Directly attributable		2,345			
28	Not directly attributable		-		-	
29	**Total attributable to regulated service**		2,345			
30	**Business support**					
31	Directly attributable		2,400			
32	Not directly attributable		-		-	
33	**Total attributable to regulated service**		2,400			
34						
35	**Operating costs directly attributable**		13,498			
36	**Operating costs not directly attributable**	-	-	-	-	-
37	**Operating expenditure**		13,498			

sch ref		
45	**5d(ii): Other Cost Allocations**	
46	**Pass through and recoverable costs**	
47	**Pass through costs**	
48	Directly attributable	275
49	Not directly attributable	-
50	**Total attributable to regulated service**	275
51	**Recoverable costs**	
52	Directly attributable	15,697
53	Not directly attributable	-
54	**Total attributable to regulated service**	15,697
55		

sch ref					
56	**5d(iii): Changes in Cost Allocations* †**			($000)	
57				CY-1	Current Year (CY)
58	**Change in cost allocation 1**			31 Mar 13	31 Mar 14
59	Cost category		Original allocation		
60	Original allocator or line items		New allocation		
61	New allocator or line items		Difference	-	-
62					
63	Rationale for change				
64					
65				CY-1	Current Year (CY)
66	**Change in cost allocation 2**			31 Mar 13	31 Mar 14
67	Cost category		Original allocation		
68	Original allocator or line items		New allocation		
69	New allocator or line items		Difference	-	-
70					
71	Rationale for change				
72					
73				CY-1	Current Year (CY)
74	**Change in cost allocation 3**			31 Mar 13	31 Mar 14
75	Cost category		Original allocation		
76	Original allocator or line items		New allocation		
77	New allocator or line items		Difference	-	-
78					
79	Rationale for change				
80					
81					

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

Company Name	The Power Company Limited
For Year Ended	31 March 2014

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref		Value allocated ($000s) Electricity distribution services
7	**5e(i):Regulated Service Asset Values**	
8		
9		
10	**Subtransmission lines**	
11	Directly attributable	43877
12	Not directly attributable	0
13	**Total attributable to regulated service**	43,877
14	**Subtransmission cables**	
15	Directly attributable	1240
16	Not directly attributable	0
17	**Total attributable to regulated service**	1,240
18	**Zone substations**	
19	Directly attributable	60028
20	Not directly attributable	0
21	**Total attributable to regulated service**	60,028
22	**Distribution and LV lines**	
23	Directly attributable	126121
24	Not directly attributable	0
25	**Total attributable to regulated service**	126,121
26	**Distribution and LV cables**	
27	Directly attributable	18641
28	Not directly attributable	0
29	**Total attributable to regulated service**	18,641
30	**Distribution substations and transformers**	
31	Directly attributable	52324
32	Not directly attributable	0
33	**Total attributable to regulated service**	52,324
34	**Distribution switchgear**	
35	Directly attributable	6812
36	Not directly attributable	0
37	**Total attributable to regulated service**	6,812
38	**Other network assets**	
39	Directly attributable	6266
40	Not directly attributable	0
41	**Total attributable to regulated service**	6,266
42	**Non-network assets**	
43	Directly attributable	7
44	Not directly attributable	0
45	**Total attributable to regulated service**	7
46		
47	**Regulated service asset value directly attributable**	315,316
48	**Regulated service asset value not directly attributable**	-
49	**Total closing RAB value**	315,316

				($000)	
57	**5e(ii): Changes in Asset Allocations* †**				
58				CY-1	Current Year (CY)
59				31 Mar 13	31 Mar 14
60	**Change in asset value allocation 1**				
61	Asset category		Original allocation		
62	Original allocator or line items		New allocation		
63	New allocator or line items		Difference	-	-
64					
65	Rationale for change				
66					
67				CY-1	Current Year (CY)
68	**Change in asset value allocation 2**			31 Mar 13	31 Mar 14
69	Asset category		Original allocation		
70	Original allocator or line items		New allocation		
71	New allocator or line items		Difference	-	-
72					
73	Rationale for change				
74					
75					
76				CY-1	Current Year (CY)
77	**Change in asset value allocation 3**			31 Mar 13	31 Mar 14
78	Asset category		Original allocation		
79	Original allocator or line items		New allocation		
80	New allocator or line items		Difference	-	-
81					
82	Rationale for change				
83					
84					

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

Company Name	The Power Company Limited
For Year Ended	31 March 2014

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			($000)	($000)
7		**6a(i): Expenditure on Assets**		
8		Consumer connection		3,263
9		System growth		10,183
10		Asset replacement and renewal		7,915
11		Asset relocations		43
12		Reliability, safety and environment:		
13		Quality of supply	275	
14		Legislative and regulatory	-	
15		Other reliability, safety and environment	824	
16		**Total reliability, safety and environment**		1,099
17		**Expenditure on network assets**		22,503
18		Non-network assets		-
19				
20		**Expenditure on assets**		22,503
21	*plus*	Cost of financing		-
22	*less*	Value of capital contributions		1,910
23	*plus*	Value of vested assets		-
24				
25		**Capital expenditure**		20,593

sch ref			($000)
26		**6a(ii): Subcomponents of Expenditure on Assets (where known)**	
27		Energy efficiency and demand side management, reduction of energy losses	-
28		Overhead to underground conversion	-
29		Research and development	-

sch ref			($000)	($000)
30		**6a(iii): Consumer Connection**		
31		*Consumer types defined by EDB**		
32		Non Half Hour Individuals	743	
33		Non- Domestic	1,456	
34		Domestic	1,064	
35				
36		Distrbuted Generation Connection	1	
37		** include additional rows if needed*		
38		**Consumer connection expenditure**		3,263
39				
40	*less*	Capital contributions funding consumer connection expenditure	1,876	
41		**Consumer connection less capital contributions**		1,387

sch ref			System Growth ($000)	Asset Replacement and Renewal ($000)
42		**6a(iv): System Growth and Asset Replacement and Renewal**		
43				
44				
45		Subtransmission	3,172	92
46		Zone substations	6,871	1,962
47		Distribution and LV lines	-	4,510
48		Distribution and LV cables	140	-
49		Distribution substations and transformers	-	1,202
50		Distribution switchgear	-	149
51		Other network assets	-	-
52		**System growth and asset replacement and renewal expenditure**	10,183	7,915
53	*less*	Capital contributions funding system growth and asset replacement and renewal	-	34
54		**System growth and asset replacement and renewal less capital contributions**	10,183	7,882
55				

sch ref			($000)	($000)
56		**6a(v): Asset Relocations**		
57		*Project or programme**		
58				
59				
60				
61				
62				
63		** include additional rows if needed*		
64		All other asset relocations projects or programmes	43	
65		**Asset relocations expenditure**		43
66	*less*	Capital contributions funding asset relocations	-	
67		**Asset relocations less capital contributions**		43

75		**6a(vi): Quality of Supply**		
76		*Project or programme**	($000)	($000)
77				
78				
79				
80				
81				
82		** include additional rows if needed*		
83		All other quality of supply projects or programmes	275	
84		**Quality of supply expenditure**		275
85	*less*	Capital contributions funding quality of supply	-	
86		**Quality of supply less capital contributions**		275
87		**6a(vii): Legislative and Regulatory**		
88		*Project or programme**	($000)	($000)
89				
90				
91				
92				
93				
94		** include additional rows if needed*		
95		All other legislative and regulatory projects or programmes		
96		**Legislative and regulatory expenditure**		-
97	*less*	Capital contributions funding legislative and regulatory		
98		**Legislative and regulatory less capital contributions**		-
99		**6a(viii): Other Reliability, Safety and Environment**		
100		*Project or programme**	($000)	($000)
101		Earth Upgrades	573	
102				
103				
104				
105				
106		** include additional rows if needed*		
107		All other reliability, safety and environment projects or programmes	251	
108		**Other reliability, safety and environment expenditure**		824
109	*less*	Capital contributions funding other reliability, safety and environment	-	
110		**Other reliability, safety and environment less capital contributions**		824
111				
112		**6a(ix): Non-Network Assets**		
113		**Routine expenditure**		
114		*Project or programme**	($000)	($000)
115				
116				
117				
118				
119				
120		** include additional rows if needed*		
121		All other routine expenditure projects or programmes		
122		**Routine expenditure**		-
123		**Atypical expenditure**		
124		*Project or programme**	($000)	($000)
125				
126				
127				
128				
129				
130		** include additional rows if needed*		
131		All other atypical expenditure projects or programmes		
132		**Atypical expenditure**		-
133				
134		**Non-network assets expenditure**		-

Company Name	The Power Company Limited
For Year Ended	31 March 2014

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

This schedule requires a breakdown of operating 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 operating 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	2,920	
9	Vegetation management	1,379	
10	Routine and corrective maintenance and inspection	3,431	
11	Asset replacement and renewal	1,022	
12	**Network opex**		8,752
13	System operations and network support	2,345	
14	Business support	2,400	
15	**Non-network opex**		4,745
16			
17	**Operational expenditure**		13,498
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		323
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 2014

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	53,184	54,040	2%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	2,720	3,263	20%
11	System growth	9,888	10,183	3%
12	Asset replacement and renewal	5,614	7,915	41%
13	Asset relocations	58	43	(26%)
14	Reliability, safety and environment:			
15	Quality of supply	262	275	5%
16	Legislative and regulatory	-	-	-
17	Other reliability, safety and environment	925	824	(11%)
18	**Total reliability, safety and environment**	1,187	1,099	(7%)
19	**Expenditure on network assets**	19,467	22,503	16%
20	Non-network capex	798	-	(100%)
21	**Expenditure on assets**	20,265	22,503	11%
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	2,573	2,920	13%
24	Vegetation management	1,255	1,379	10%
25	Routine and corrective maintenance and inspection	2,796	3,431	23%
26	Asset replacement and renewal	930	1,022	10%
27	**Network opex**	7,554	8,752	16%
28	System operations and network support	1,992	2,345	18%
29	Business support	3,350	2,400	(28%)
30	**Non-network opex**	5,342	4,745	(11%)
31	**Operational expenditure**	12,896	13,498	5%
32	**7(iv): Subcomponents of Expenditure on Assets (where known)**			
33	Energy efficiency and demand side management, reduction of energy losses	-	-	-
34	Overhead to underground conversion	-	-	-
35	Research and development	-	-	-
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses	-	125	-
39	Direct billing	-	-	-
40	Research and development	-	-	-
41	Insurance	356	323	(9%)
42				

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

44 *2 From the nominal dollar expenditure forecast and disclosed in the second to last AMP as the year CY+1 forecast*

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2014**
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	6,053	34,534	-	28,483,406				
16	Domestic	Residential	Standard	20,475	173,502	-	143,671,686				
17	Non-Domestic	Commerical	Standard	7,841	191,141	-	157,471,547				
18	Individual non half hour	Commerical	Standard	78	10,851	-	8,941,413				
19	Individual half hour	Commerical	Standard	163	154,619	111,692,318	-				
20	Non-Standard	Commerical	Non-standard	4	119,659	78,849,284	-				
21											
22											
23											
24											
25	*Add extra rows for additional consumer groups or price category codes as necessary*										
26			**Standard consumer totals**	34,610	564,647	111,692,318	338,568,052	-	-	-	-
27			**Non-standard consumer totals**	4	119,659	78,849,284	-	-	-	-	-
28			**Total for all consumers**	34,614	684,306	190,541,602	338,568,052	-	-	-	-

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 (if applicable)	Total distribution line charge revenue	Total transmission line charge revenue (if available)	Line charge revenues ($000) by price component — Price component: Fixed; Rate (eg, $/day, $/kWh, etc.): $/Day	Variable; $/kwh				
Low user	Residential	Standard	$3,663	-	$2,935	$728	$76	$3,587				
Domestic	Residential	Standard	$18,886	-	$15,121	$3,765	$8,058	$10,828				
Non-Domestic	Commerical	Standard	$19,767	-	$15,835	$3,932	$8,006	$11,761				
Individual non half hour	Commerical	Standard	$751	-	$481	$270	$75	$676				
Individual half hour	Commerical	Standard	$4,971	-	$2,145	$2,827	$2,660	$2,311				
Non-Standard	Commerical	Non-standard	$5,903	-	$1,792	$4,111	$5,903	-				
Generation	Commerical	Non-standard	$99	-	$99		$99	-				
			-									
			-									
			-									
		Standard consumer totals	$48,039	-	$36,517	$11,521	$18,876	$29,163	-	-	-	-
		Non-standard consumer totals	$6,002	-	$1,891	$4,111	$6,002	-	-	-	-	-
		Total for all consumers	$54,040	-	$38,408	$15,632	$24,878	$29,163	-	-	-	-

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

Check: OK

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end	2

Company Name	The Power Company Limited
For Year Ended	31 March 2014
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.	86,129	87,163	1,034	3
10	All	Overhead Line	Wood poles	No.	22,180	21,589	(591)	3
11	All	Overhead Line	Other pole types	No.	-	-	-	N/A
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	833	846	13	3
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	N/A
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	6	6	-	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.	40	40	-	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.	46	46	-	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	N/A
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	229	227	(2)	3
29	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	12	12	-	4
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	33	33	-	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	108	110	2	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	60	60	-	4
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	56	56	-	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	6,667	6,753	86	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	N/A
37	HV	Distribution Line	SWER conductor	km	5	5	(0)	4
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	83	87	4	3
39	HV	Distribution Cable	Distribution UG PILC	km	42	42	(0)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	N/A
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	33	31	(2)	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	2	2	-	4
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	12,955	12,949	(6)	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.	75	76	1	4
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	10,368	10,345	(23)	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	529	550	21	3
48	HV	Distribution Transformer	Voltage regulators	No.	66	61	(5)	4
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	N/A
50	LV	LV Line	LV OH Conductor	km	842	854	12	3
51	LV	LV Cable	LV UG Cable	km	211	215	4	1
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	346	347	1	3
53	LV	Connections	OH/UG consumer service connections	No.	36,464	36,726	262	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	493	496	3	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 2014
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

Disclosure Year (year ended): 31 March 2014

Number of assets at disclosure year end by installation date

sch ref	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	No. with Age unknown	Total assets at year end	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	-	685	1	62	1,483	78,572	402	84	170	111	86	88	106	140	360	344	849	865	728	753	717	115	442	87,163	-	3
11	All	Overhead Line	Wood poles	No.	-	5	112	832	8,769	91	5,225	712	607	691	740	493	462	751	796	1,042	115	2	1	3	5	-	135	21,589	-	3
12	All	Overhead Line	Other pole types	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	-	132	153	115	150	138	59	14	8	26	-	-	0	27	22	1	-	0	-	-	-	1	846	-	3
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	-	0	-	1	-	0	1	0	0	1	-	2	0	-	-	-	-	-	-	0	6	-	3
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	0	-	-	-	-	-	-	0	1	-	3
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	2	8	11	9	7	-	1	1	-	-	-	-	-	-	-	-	-	1	-	-	-	40	-	3
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	-	1	-	11	6	1	-	-	2	2	2	13	1	5	-	-	1	1	-	-	46	-	4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	-	13	11	20	27	54	3	25	4	3	12	5	8	18	3	8	1	1	8	3	-	-	227	-	3
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	7	-	-	-	5	-	-	-	-	-	-	-	-	-	12	-	4
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	-	2	2	5	9	2	-	-	-	-	2	2	5	2	-	1	1	-	-	-	-	33	-	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	-	10	-	23	51	-	-	-	-	-	-	-	6	-	-	-	-	17	3	-	-	110	-	4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	1	1	10	22	6	-	1	1	4	1	1	-	2	3	1	-	1	5	-	-	60	-	4
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	3	-	2	11	11	9	2	5	-	2	2	-	2	-	2	1	-	-	3	1	-	-	-	56	-	4
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	-	0	209	736	3,451	1,129	317	48	100	102	70	60	54	52	68	101	75	30	49	48	22	1	33	6,753	-	3
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
48	HV	Distribution Line	SWER conductor	km	-	-	-	-	4	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	3
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	-	-	0	16	5	6	2	4	3	5	9	4	5	8	7	2	2	1	2	1	-	6	87	-	3
50	HV	Distribution Cable	Distribution UG PILC	km	-	-	-	0	14	5	8	1	0	1	0	-	1	1	3	1	1	2	1	2	-	-	2	42	-	3
51	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	-	-	2	10	11	-	1	-	-	1	2	1	-	1	1	-	-	-	1	-	-	31	-	4
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-	-	-	2	-	4
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	11	2	240	516	1,585	2,660	1,761	161	413	499	402	425	353	367	535	516	593	535	538	383	271	12	171	12,949	-	3
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	-	-	-	-	1	3	12	-	-	1	14	6	4	3	13	8	3	2	1	5	-	-	-	76	-	4
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	11	2	212	106	1,525	2,442	1,663	136	375	445	318	326	245	250	420	348	379	320	354	252	178	4	34	10,345	-	3
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	-	-	1	7	99	93	43	5	18	25	28	29	26	33	25	31	22	6	15	23	15	-	6	550	-	3
59	HV	Distribution Transformer	Voltage regulators	No.	-	2	1	-	-	-	-	-	4	2	4	7	3	4	16	18	-	-	-	-	-	-	-	61	-	4
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
61	LV	LV Line	LV OH Conductor	km	-	-	19	76	519	110	44	3	9	12	7	5	4	7	5	6	6	5	5	3	5	0	3	854	-	3
62	LV	LV Cable	LV UG Cable	km	-	-	0	2	81	20	12	1	1	4	4	7	8	17	21	8	8	6	5	4	3	0	3	215	-	3
63	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	-	-	0	14	242	40	16	1	3	2	1	3	3	4	2	2	1	3	1	1	2	-	7	347	-	3
64	LV	Connections	OH/UG consumer service connections	No.	-	214	2,185	5,389	7,172	8,096	7,170	252	351	445	447	426	482	518	572	694	532	433	485	364	421	78	-	36,726	1,626	3
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	-	-	10	56	86	149	19	14	10	3	4	22	10	31	20	11	7	6	31	6	1	-	496	-	3
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	3
67	All	Capacitor Banks	Capacitors including controls	No	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-	-	-	-	6	-	4
68	All	Load Control	Centralised plant	Lot	-	-	-	-	-	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	4
69	All	Load Control	Relays	No	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A
70	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	N/A

Company Name	The Power Company Limited
For Year Ended	31 March 2014
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	386	-	386
13	33kV	460	6	466
14	SWER (all SWER voltages)	5	3	8
15	22kV (other than SWER)	-	-	-
16	6.6kV to 11kV (inclusive—other than SWER)	6,753	126	6,879
17	Low voltage (< 1kV)	854	215	1,069
18	**Total circuit length (for supply)**	8,458	351	8,809
19				
20	Dedicated street lighting circuit length (km)	271	77	347
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	484	6%	
25	Rural	4,738	56%	
26	Remote only	829	10%	
27	Rugged only	1,858	22%	
28	Remote and rugged	548	6%	
29	Unallocated overhead lines	-	-	
30	**Total overhead length**	8,458	100%	
31				
32		**Circuit length (km)**	**(% of total circuit length)**	
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,687	19%	
34		**Circuit length (km)**	**(% of total overhead length)**	
35	Overhead circuit requiring vegetation management	1,376	16%	

Company Name	**The Power Company Limited**
For Year Ended	**31 March 2014**

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 2014**
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	340	
12		Non domestic	57	
13		Non - half hour Individual	3	
14		Half hour Individual	-	
15				
16		** include additional rows if needed*		
17		**Connections total**	400	
18				
19		**Distributed generation**		
20		Number of connections made in year	23	**connections**
21		Capacity of distributed generation installed in year	0	**MVA**
22		**9e(ii): System Demand**		
23				
24				
25		**Maximum coincident system demand**	**Demand at time of maximum coincident demand (MW)**	
26		GXP demand	88	
27	*plus*	Distributed generation output at HV and above	49	
28		**Maximum coincident system demand**	137	
29	*less*	Net transfers to (from) other EDBs at HV and above	2	
30		**Demand on system for supply to consumers' connection points**	135	
31		**Electricity volumes carried**	**Energy (GWh)**	**Energy (GWh)**
32		Electricity supplied from GXPs	597	
33	*less*	Electricity exports to GXPs	55	
34	*plus*	Electricity supplied from distributed generation	215	
35	*less*	Net electricity supplied to (from) other EDBs	19	
36		**Electricity entering system for supply to consumers' connection points**	738	
37	*less*	Total energy delivered to ICPs	684	
38		**Electricity losses (loss ratio)**	53	7.2%
39				
40		**Load factor**	1	
41		**9e(iii): Transformer Capacity**		
42			**(MVA)**	
43		Distribution transformer capacity (EDB owned)	406	
44		Distribution transformer capacity (Non-EDB owned)	42	
45		**Total distribution transformer capacity**	448	
46				
47		**Zone substation transformer capacity**	404	

Company Name	The Power Company Limited
For Year Ended	31 March 2014
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**			
9	**Interruptions by class**	Number of interruptions		
10	Class A (planned interruptions by Transpower)	-		
11	Class B (planned interruptions on the network)	685		
12	Class C (unplanned interruptions on the network)	536		
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)	-		
17	Class H (planned interruptions caused by another disclosing entity)	-		
18	Class I (interruptions caused by parties not included above)	-		
19	Total	1,221		
20				
21	**Interruption restoration**	≤3Hrs	>3hrs	
22	Class C interruptions restored within	437	99	
23				
24	**SAIFI and SAIDI by class**	SAIFI	SAIDI	
25	Class A (planned interruptions by Transpower)	-	-	
26	Class B (planned interruptions on the network)	0.32	66.8	
27	Class C (unplanned interruptions on the network)	2.55	111.0	
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)	-	-	
32	Class H (planned interruptions caused by another disclosing entity)	-	-	
33	Class I (interruptions caused by parties not included above)	-	-	
34	Total	2.87	177.8	
35				
36	**Normalised SAIFI and SAIDI**	Normalised SAIFI	Normalised SAIDI	
37	Classes B & C (interruptions on the network)	2.87	177.8	
38				
39	**Quality path normalised reliability limit**	SAIFI reliability limit	SAIDI reliability limit	
40	SAIFI and SAIDI limits applicable to disclosure year*	-	-	
41	** not applicable to exempt EDBs*			
42	**10(ii): Class C Interruptions and Duration by Cause**			
43				
44	**Cause**	SAIFI	SAIDI	
45	Lightning	0.18	2.4	
46	Vegetation	0.22	15.3	
47	Adverse weather	0.11	4.9	
48	Adverse environment	-	-	
49	Third party interference	0.31	21.5	
50	Wildlife	-	-	
51	Human error	0.01	0.1	
52	Defective equipment	1.18	55.6	
53	Cause unknown	0.53	11.1	
62	**10(iii): Class B Interruptions and Duration by Main Equipment Involved**			
63				
64	**Main equipment involved**	SAIFI	SAIDI	
65	Subtransmission lines	0.00	0.0	
66	Subtransmission cables	-	-	
67	Subtransmission other	-	-	
68	Distribution lines (excluding LV)	0.30	63.8	
69	Distribution cables (excluding LV)	0.00	0.0	
70	Distribution other (excluding LV)	0.01	2.9	
71	**10(iv): Class C Interruptions and Duration by Main Equipment Involved**			
72				
73	**Main equipment involved**	SAIFI	SAIDI	
74	Subtransmission lines	0.71	15.7	
75	Subtransmission cables	-	-	
76	Subtransmission other	0.08	0.4	
77	Distribution lines (excluding LV)	1.60	90.8	
78	Distribution cables (excluding LV)	0.07	1.3	
79	Distribution other (excluding LV)	0.10	2.8	
80	**10(v): Fault Rate**			
81	**Main equipment involved**	Number of Faults	Circuit length (km)	Fault rate (faults per 100km)
82	Subtransmission lines	24	846	2.84
83	Subtransmission cables	-	6	-
84	Subtransmission other	2		
85	Distribution lines (excluding LV)	442	6,758	6.54
86	Distribution cables (excluding LV)	5	129	3.88
87	Distribution other (excluding LV)	63		
88	Total	536		

SCHEDULE 14 MANDATORY EXPLANATORY NOTES

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

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 2.5.2.

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 12 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 clause 2.7.1(2).

Box 1: Explanatory comment on return on investment

The Power Company Limited achieved a post-tax WACC of 3.91% below the 75th percentile estimate of post-tax WACC of 6.14% and a 4.59% vanilla WACC below the 75th percentile estimate of vanilla WACC of 6.83%.

For the 2013 year, with the ROI corrected adjusted for the exclusion of the revaluation adjustment in the tax calculation (original reported figures in brackets), gives the post-tax WACC of 3.26% (3.01%) below the 75th percentile estimate of post-tax WACC of 6.56% and the 4.03% (3.78%) vanilla WACC below the 75th percentile estimate of vanilla WACC of 7.34%.

No items were reclassified.

Regulatory Profit (Schedule 3)

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

   5.1 a description of material items included in ‘other regulatory line income’ other than gains and losses on asset sales, as disclosed in 3(i) of Schedule 3

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

Box 2: Explanatory comment on regulatory profit

Included in other regulated income is an amount of $518k for lines charges sold to another lines company.

In line with standard practise distribution transformers are replaced and sold for their scrap metal value leading to a loss on disposal.

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 clause 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 clause 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 2013 figure as a starting point with inflationary indexing over the year to 31 March 2014 plus additions less disposals.

Due to changes in IFRS 11 “Joint Ventures” some non-network assets belonging to PowerNet are no longer included in the RAB. These have been eliminated in the allocated RAB under the “adjustments resulting from asset allocation” category, and adjusted in the unallocated RAB under the “asset disposal” category.

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

8. In the box below, provide descriptions and workings of the following items, as recorded in the asterisked categories in 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 $1k cost of easements which is a tax deductible expense.

Income included in regulatory profit / (loss) before tax but not taxable is the $4,671k of revaluations for the year

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:	$	720
	$	720
Tax Rate:		28%
Temporary Differences	$	202

Related party transactions: disclosure of related party transactions (Schedule 5b)

10. In the box below, provide descriptions of related party transactions beyond those disclosed on schedule 5b including identification and descriptions as to the nature of directly attributable costs disclosed under clause 2.3.6(1)(b).

Box 7: Related party transactions

PowerNet Limited is an incorporated break even joint venture owned 50% by The Power Company Limited and 50% by Electricity Invercargill Limited.

PowerNet Limited carries out project management and asset construction to develop The Power Company Limited's electricity network.

Cost allocation (Schedule 5d)

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

Box 8: Cost allocation

All costs are directly attributable, as all costs have been passed through to or invoiced to the Power Company Limited. In previous years some of the costs originating in PowerNet were classified as not directly attributable costs, this has changed due to changes in IFRS 11 "Joint Ventures".

Asset allocation (Schedule 5e)

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

Box 9: Commentary on asset allocation

All network assets are directly attributable, as are non-network assets belonging to the parent company.

Previously non-network assets from PowerNet were included as not directly attributable assets. These assets are no longer included in the RAB due to changes in IFRS 11 "Joint Ventures".

Capital Expenditure for the Disclosure Year (Schedule 6a)

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

    13.1 a description of the materiality threshold applied to identify material projects and programmes described in Schedule 6a;

    13.2 information on reclassified items in accordance with clause 2.7.1(2),

Box 10: Explanation of capital expenditure for the disclosure year

The materiality threshold of programmes or projects identified during the disclosure year was set at $500k.
No items were reclassified during the disclosure year.

Operational Expenditure for the Disclosure Year (Schedule 6b)

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

    14.1 commentary on assets replaced or renewed with asset replacement and renewal operating expenditure, as reported in 6b(i) of Schedule 6b;

    14.2 information on reclassified items in accordance with clause 2.7.1(2);

    14.3 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 11: Explanation of operational 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.

Costs previously classified as indirect costs in the System operations and network support and Business support categories are now all classified as directly attributable costs, as under the new structure for the lines company all costs go directly to the EDB.

Changes in accounting standard IFRS 11 "Joint Ventures" requires joint ventures to be equity accounted rather than line by line or proportionately consolidated. The non-network assets of the PowerNet joint venture are now removed from the RAB, however the cost associated with those assets, including depreciation and return on investment are now recorded in operating expenditure as a related party transaction. This will see an increase in operating expenditure that was previously represented by an investment return on non-network assets.

There was no material atypical expenditure disclosed in Schedule 6b.

Variance between forecast and actual expenditure (Schedule 7)

15. 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 clause 2.7.1(2).

Box 12: Explanatory comment on variance in actual to forecast expenditure

Capital Expenditure on Assets:

The actual expenditure on network assets was 7% under budget.

Consumer connection:

- 20% more customer connections than was forecast. Actuals depend on regional growth and development.

System Growth:

- Overall capex managed in line with budget.

Asset replacement and renewal:

- 41% overspend due to unexpected safety issues, timing issues and unforeseen poor condition of some equipment.

Asset Relocations:

- This type of work is customer driven with the reactive element lower than estimated.

Reliability, Safety and Environment:

- Overall capex managed in line with budget.

Operational Expenditure:

Network opex was overspent and 16% more than budget.

Service interruptions and emergencies:

- 13% above budget due to contractor charging error found

Vegetation management:

- Overall opex managed in line with budget.

Routine and corrective maintenance and inspection:

- 23% over budget due to increased safety and seismic inspections.

Asset replacement and renewal:

- Overall opex managed in line with budget.

Most of the non-network capex (formally from PowerNet) is no longer included in the regulated business.

Information relating to revenue and quantities for the disclosure year

16. In the box below provide-

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

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

Box 13: Explanatory comment relating to revenue for the disclosure year

Year ended 31 March 2014:

- Target revenue for the 2013-14 year was $53,184. The total billed revenue for the 2013-14 year was $54,040k, a 1.6% variation. This variation can be explained by distribution and transmission price increases in 2014 off-set by warmer than anticipated weather over the year and The Power Company Limited sponsored Southland Warm Homes Trust household insulation and energy efficiency project.

Network Reliability for the Disclosure Year (Schedule 10)

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

Box 14: Commentary on network reliability for the disclosure year

The SAIDI of 178 minutes did not meet the Statement of Intent target of 162 minutes; however was an improvement on the 2012/13 measure of 191 minutes.

The SAIFI of 2.87 times was better than the Statement of Intent target of 3.21 times and the 2012/13 measure of 2.59 times.

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 completeness and accuracy of recorded faults and control over the completeness and accuracy of installation control point ('ICP') data, included in the SAIDI and SAIFI calculations, is limited throughout the year.

Insurance cover

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

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

 18.2 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: Explanation of insurance cover

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

- Substations and network equipment are insured for $109.0 million.

Lines and cables are un-insured; the cost of covering this risk through insurance is regarded as too expensive relative to the risk. The company's view is that an EDB should recover prudent costs for rectifying for catastrophic events through future line charges.

The Power Company Limited does not self-insure and doesn't recognise the cost of self-insurance.

SCHEDULE 14A MANDATORY EXPLANATORY NOTES ON FORECAST INFORMATION

(In this Schedule, clause references are to the Electricity Distribution Information Disclosure Determination 2012)

19. This Schedule provides for EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.5.

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

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

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

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

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

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

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

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

Nominal Prices are based on economic assumptions obtained from NZIER Consensus Forecast (September 2013) as follows:

	2014	2015	2016	2017	2018
Inflation (CPI)	1.7%	2.2%	2.4%	2.4%	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)

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

    23.1 additional explanatory comment to reports prepared in accordance with clauses 2.3.1, 2.4.21, 2.4.22, 2.5.1, 2.5.2, and 2.6.5;

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

24. 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.

25. Provide additional explanatory comment in the box below.

Box 1: Voluntary explanatory comment on disclosed information
Information disclosed in Schedule 9b was sourced in 2014 from a better source of information than in 2013.

6. AUDITORS' REPORT

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Independent Auditors' Report

To the Directors of The Power Company Limited and the Commerce Commission as a recipient of the Report

Assurance Report Pursuant to Electricity Distribution Information Disclosure Determination 2012

We have completed our assurance engagement in respect of the compliance of The Power Company Limited (the 'Company') in the preparation of Schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the SAIDI and SAIFI information disclosed in Schedule 10 and the explanatory notes in boxes 1 to 12 in Schedule 14 ('the Schedules') for the disclosure year ended 31 March 2014, have been prepared, in all material respects, in accordance with the Electricity Distribution Disclosure Information Determination 2012 (the 'Determination').

Directors' Responsibilities

The Directors are responsible for preparation of the Schedules in accordance with the Determination and ensuring the Company keeps records to enable the preparation of the Schedules that are free from material misstatement.

Auditors' Responsibilities

Our responsibility is to express an opinion on whether the Company has complied, in all material respects, with the Determination in the preparation of the Schedules for the year ended 31 March 2014 and report our opinion to you.

Basis of Opinion

Our engagement has been conducted in accordance with ISAE (NZ) 3000, Assurance Engagements Other than Audits or Reviews of Historical Financial Information and SAE 3100 Compliance Engagements to obtain reasonable assurance that the Company has complied, in all material respects, with the Determination in the preparation of the Schedules for the year ended 31 March 2014.

The procedures we performed were based on our professional judgment, including assessment of the risks of material misstatement in the Audited Schedules, whether due to fraud or error. In making those risk assessments, we considered internal controls relevant to the Company's preparation of the Schedules to design procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Our procedures included analytical procedures, evaluating the appropriateness of assumptions used and whether they have been consistently applied, and agreement of the Schedules to, or reconciling with, source systems and underlying records. We included an assessment of the significant judgements made by the Company in the preparation of the disclosure information and also evaluated the overall adequacy of the presentation of supporting information and explanations.

These procedures have been undertaken to form an opinion as to whether the Company has complied, in all material respects, with the Determination in the preparation of the Schedules for the year ended 31 March 2014.

We believe that the recorded evidence and explanations we have obtained is sufficient and appropriate to provide a basis for our opinion expressed below

Use of Report

This report has been prepared for the Directors of the Company in accordance with section 2.8.1(1) of the Determination and is provided solely to assist you in establishing that compliance requirements have been met. We acknowledge that the Directors will provide the report to the Commerce Commission in accordance with clause 2.8.1(1)(a) of the Determination.

The report has been prepared in accordance with the scope and terms of our letter of engagement with the Company dated 5 August 2013. The terms and conditions are attached and form part of this report and are applicable to the Commerce Commission. 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, or for any purpose other than that for which it was prepared.

Inherent Limitations

Because of the inherent limitations in evidence gathering procedures, it is possible that fraud, error or non-compliance may occur and not be detected. As the procedures performed for this engagement are not performed continuously throughout the year and the procedures performed in respect of the Company's compliance with the Determination are undertaken on a test basis, our engagement cannot be relied on to detect all instances where the Company may not have complied with the Determination. The opinion expressed in this report has been formed on the above basis.

Independence

Other than this engagement, the annual audit of the Company's financial statements and the provision of advice on industry related matters, we have no relationship with or interests in the Company or any of its subsidiaries. We are not aware of any relationship between our firm and The Power Company Limited that, in our professional judgment, may reasonably be thought to impair our independence.

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

As described in Box 14 of Schedule 14, there are inherent limitations in ability of the Company to collect and record the network reliability information required to be disclosed in Schedules 10(i) to 10(iv). Consequently there is no independent evidence available to support the completeness and accuracy of recorded faults and control over the completeness and accuracy of interconnection point ('ICP') data included in the SAIDI and SAIFI outage statistics is limited throughout the year.

There are no practical audit procedures that we could adopt to confirm independently that all the outage and ICP data was properly recorded 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 completeness and accuracy of the data that forms the basis of the compilation of Schedules 10(i) to 10(iv). In these respects alone we have not obtained all the information and explanations that we have required.

Qualified Opinion

In our opinion, except for the matters described in the Basis of Qualified Opinion paragraph above:

- As far as appears from our examination, proper records have been kept by the Company to enable the complete and accurate compilation of the Schedules;
- The information used in the preparation of the Schedules 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; and
- The Company has complied, in all material respects, with the Determination in preparing the Schedules.

PricewaterhouseCoopers

Chartered Accountants Christchurch, New Zealand
29 August 2014

6. DIRECTORS' CERTIFICATE

Schedule 18: Certification for Year-End Disclosures

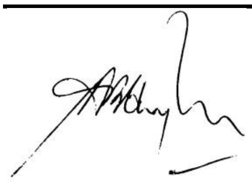
Clause 2.9.2 of Section 2.9

We, Alan Bertram Harper and Maryann Louise Macpherson, 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 and 2.3.2; and clauses 2.4.21 and 2.4.22; clauses 2.5.1 and 2.5.2; and clauses 2.7.1 and 2.7.2 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 14a has been properly extracted from the 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.

In respect of related party costs and revenues recorded in accordance with clauses 2.3.6(1) (when valued in accordance with clause 2.2.11(5)(h)(ii) of the Electricity Distribution Services Input Methodologies Determination 2010), 2.3.6(2)(f) and 2.3.7(2)(b), we certify that, having made all reasonable enquiry, including enquiries of our related parties, we are satisfied that to the best of our knowledge and belief the costs and revenues recorded for related party transactions reasonably reflect the price or prices that would have been paid or received had these transactions been at arm's-length.



Alan Bertram Harper **Maryann Louise Macpherson**

27 AUGUST 2014