COUNTIESPOWER

Information Disclosure prepared in accordance with the

Electricity Distribution Information Disclosure Determination 2012

For the Year Ended 31 March 2016

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Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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**

8	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)
9 **Operational expenditure**	20,850	291	100,829	3,631	36,600
10 Network	7,699	107	37,231	1,341	13,515
11 Non-network	13,151	184	63,598	2,290	23,086
12					
13 **Expenditure on assets**	26,295	367	127,162	4,580	46,159
14 Network	25,679	358	124,182	4,472	45,077
15 Non-network	616	9	2,981	107	1,082

16

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

18	Revenue per GWh energy delivered to ICPs ($/GWh)	Revenue per average no. of ICPs ($/ICP)
19 **Total consumer line charge revenue**	87,475	1,221
20 Standard consumer line charge revenue	95,712	1,142
21 Non-standard consumer line charge revenue	38,879	446,536

22

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

24

25 Demand density	36	*Maximum coincident system demand per km of circuit length (for supply) (kW/km)*
26 Volume density	174	*Total energy delivered to ICPs per km of circuit length (for supply) (MWh/km)*
27 Connection point density	12	*Average number of ICPs per km of circuit length (for supply) (ICPs/km)*
28 Energy intensity	13,957	*Total energy delivered to ICPs per average number of ICPs (kWh/ICP)*

29

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

31	($000)	% of revenue
32 Operational expenditure	11,566	23.77%
33 Pass-through and recoverable costs excluding financial incentives and wash-ups	11,834	24.32%
34 Total depreciation	7,623	15.67%
35 Total revaluations	1,337	2.75%
36 Regulatory tax allowance	2,649	5.44%
37 Regulatory profit/(loss) including financial incentives and wash-ups	16,326	33.55%
38 **Total regulatory income**	48,660	

39

40 **1(v): Reliability**

41

42 Interruption rate	11.43	*Interruptions per 100 circuit km*

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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).
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sch ref

		CY-2	CY-1	Current Year CY
7	**2(i): Return on Investment**			
8		31 Mar 14	31 Mar 15	31 Mar 16
9	**ROI – comparable to a post tax WACC**	%	%	%
10	Reflecting all revenue earned	7.86%	5.79%	6.90%
11	Excluding revenue earned from financial incentives	7.86%	5.79%	6.90%
12	Excluding revenue earned from financial incentives and wash-ups	7.86%	5.79%	6.90%
13				
14	**Mid-point estimate of post tax WACC**	5.43%	6.10%	5.37%
15	25th percentile estimate	4.71%	5.39%	4.66%
16	75th percentile estimate	6.14%	6.82%	6.09%
17				
18				
19	**ROI – comparable to a vanilla WACC**			
20	Reflecting all revenue earned	8.54%	6.58%	7.55%
21	Excluding revenue earned from financial incentives	8.54%	6.58%	7.55%
22	Excluding revenue earned from financial incentives and wash-ups	8.54%	6.58%	7.55%
23				
24	**WACC rate used to set regulatory price path**			
25				
26	**Mid-point estimate of vanilla WACC**	6.11%	6.89%	6.02%
27	25th percentile estimate	5.39%	6.17%	5.30%
28	75th percentile estimate	6.83%	7.60%	6.74%
29				

30	**2(ii): Information Supporting the ROI**		($000)	
31				
32	Total opening RAB value	228,249		
33	*plus* Opening deferred tax	(9,203)		
34	**Opening RIV**		219,046	
35				
36	**Line charge revenue**		48,525	
37				
38	Expenses cash outflow	23,400		
39	*add* Assets commissioned	9,361		
40	*less* Asset disposals	247		
41	*add* Tax payments	1,379		
42	*less* Other regulated income	135		
43	**Mid-year net cash outflows**		33,758	
44				
45	**Term credit spread differential allowance**		–	
46				
47	Total closing RAB value	231,077		
48	*less* Adjustment resulting from asset allocation	(0)		
49	*less* Lost and found assets adjustment	–		
50	*plus* Closing deferred tax	(10,473)		
51	**Closing RIV**		220,604	
52				
53	**ROI – comparable to a vanilla WACC**			7.55%
54				
55	Leverage (%)			44%
56	Cost of debt assumption (%)			5.26%
57	Corporate tax rate (%)			28%
58				
59	**ROI – comparable to a post tax WACC**			6.90%
60				

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

SCHEDULE 2: REPORT ON RETURN ON INVESTMENT

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

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sch ref

61 **2(iii): Information Supporting the Monthly ROI**

62

63 **Opening RIV** N/A

64

65

66		Line charge revenue	Expenses cash outflow	Assets commissioned	Asset disposals	Other regulated income	Monthly net cash outflows
67	April						–
68	May						–
69	June						–
70	July						–
71	August						–
72	September						–
73	October						–
74	November						–
75	December						–
76	January						–
77	February						–
78	March						–
79	**Total**	–	–	–	–	–	–

80

81 **Tax payments** N/A

82

83 **Term credit spread differential allowance** N/A

84

85 **Closing RIV** N/A

86

87

88 **Monthly ROI – comparable to a vanilla WACC** N/A

89

90 **Monthly ROI – comparable to a post tax WACC** N/A

91

92 **2(iv): Year-End ROI Rates for Comparison Purposes**

93

94 **Year-end ROI – comparable to a vanilla WACC** 7.30%

95

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

97

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

99

100 **2(v): Financial Incentives and Wash-Ups**

101

102	Net recoverable costs allowed under incremental rolling incentive scheme	–
103	Purchased assets – avoided transmission charge	
104	Energy efficiency and demand incentive allowance	
105	Quality incentive adjustment	
106	Other financial incentives	
107	**Financial incentives**	–

108

109 **Impact of financial incentives on ROI** –

110

111	Input methodology claw-back	
112	Recoverable customised price-quality path costs	
113	Catastrophic event allowance	
114	Capex wash-up adjustment	
115	Transmission asset wash-up adjustment	
116	2013–2015 NPV wash-up allowance	
117	Reconsideration event allowance	
118	Other wash-ups	
119	**Wash-up costs**	–

120

121 **Impact of wash-up costs on ROI** –

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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

7		**3(i): Regulatory Profit**	**($000)**
8		**Income**	
9		Line charge revenue	48,525
10	*plus*	Gains / (losses) on asset disposals	(210)
11	*plus*	Other regulated income (other than gains / (losses) on asset disposals)	345
12			
13		**Total regulatory income**	48,660
14		**Expenses**	
15	*less*	Operational expenditure	11,566
16			
17	*less*	Pass-through and recoverable costs excluding financial incentives and wash-ups	11,834
18			
19		**Operating surplus / (deficit)**	25,260
20			
21	*less*	Total depreciation	7,623
22			
23	*plus*	Total revaluations	1,337
24			
25		**Regulatory profit / (loss) before tax**	18,974
26			
27	*less*	Term credit spread differential allowance	–
28			
29	*less*	Regulatory tax allowance	2,649
30			
31		**Regulatory profit/(loss) including financial incentives and wash-ups**	16,326
32			

33		**3(ii): Pass-through and Recoverable Costs excluding Financial Incentives and Wash-Ups**	**($000)**	
34		**Pass through costs**		
35		Rates	680	
36		Commerce Act levies	54	
37		Industry levies	102	
38		CPP specified pass through costs		
39		**Recoverable costs excluding financial incentives and wash-ups**		
40		Electricity lines service charge payable to Transpower	10,306	
41		Transpower new investment contract charges	206	
42		System operator services		
43		Distributed generation allowance	487	
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**		11,834
47				

Company Name	**Counties Power**
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SCHEDULE 3: REPORT ON REGULATORY PROFIT

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

48 **3(iii): Incremental Rolling Incentive Scheme**

		($000)	
49		**CY-1**	**CY**
50		**31 Mar 15**	**31 Mar 16**
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 11		
58	CY-4 31 Mar 12		
59	CY-3 31 Mar 13		
60	CY-2 31 Mar 14		
61	CY-1 31 Mar 15		
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	**Counties Power**
For Year Ended	**31 March 2016**

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

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

sch ref

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

	for year ended	RAB 31 Mar 12 ($000)	RAB 31 Mar 13 ($000)	RAB 31 Mar 14 ($000)	RAB 31 Mar 15 ($000)	RAB 31 Mar 16 ($000)
	Total opening RAB value	187,056	195,777	200,786	210,305	228,249
less	**Total depreciation**	5,939	6,316	6,608	7,132	7,623
plus	**Total revaluations**	2,934	1,679	3,069	176	1,337
plus	**Assets commissioned**	11,924	10,097	13,490	25,260	9,361
less	**Asset disposals**	197	452	433	360	247
plus	**Lost and found assets adjustment**					–
plus	**Adjustment resulting from asset allocation**					(0)
	Total closing RAB value	195,777	200,786	210,305	228,249	231,077

4(ii): Unallocated Regulatory Asset Base

		Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
	Total opening RAB value		228,905		228,249
less					
	Total depreciation		7,697		7,623
plus					
	Total revaluations		1,341		1,337
plus					
	Assets commissioned (other than below)	4,082		4,049	
	Assets acquired from a regulated supplier				
	Assets acquired from a related party	5,311		5,311	
	Assets commissioned		9,393		9,361
less					
	Asset disposals (other than below)	246.65		247	
	Asset disposals to a regulated supplier				
	Asset disposals to a related party				
	Asset disposals		247		247
plus	**Lost and found assets adjustment**				
plus	**Adjustment resulting from asset allocation**				(0)
	Total closing RAB value		231,695		231,077

** 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				1,200
	CPI_4^{-4}				1,193
	Revaluation rate (%)				0.59%

		Unallocated RAB * ($000)	Unallocated RAB * ($000)	RAB ($000)	RAB ($000)
	Total opening RAB value	228,905		228,249	
less	Opening value of fully depreciated, disposed and lost assets	421		421	
	Total opening RAB value subject to revaluation	228,484		227,829	
	Total revaluations		1,341		1,337

4(iv): Roll Forward of Works Under Construction

		Unallocated works under construction	Unallocated works under construction	Allocated works under construction	Allocated works under construction
	Works under construction—preceding disclosure year		1,348		1,348
plus	Capital expenditure	10,310		10,276	
less	Assets commissioned	9,393		9,361	
plus	Adjustment resulting from asset allocation				
	Works under construction - current disclosure year		2,264		2,263
	Highest rate of capitalised finance applied				

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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

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

sch ref

4(v): Regulatory Depreciation

	Unallocated RAB * ($000)	($000)	RAB ($000)	($000)
Depreciation - standard	6,769		6,769	
Depreciation - no standard life assets	927.79		853.31	
Depreciation - modified life assets				
Depreciation - alternative depreciation in accordance with CPP				
Total depreciation		7,697		7,623

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	15,689	240	21,197	77,795	39,377	37,499	10,285	4,971	21,197	228,249
less	Total depreciation	409	8	621	2,019	1,248	1,301	678	394	945.16	7,623
plus	Total revaluations	92	1	124	456	231	219	60	29	123	1,337
plus	Assets commissioned	1,560	–	500	4,629	–	1,583	357	389	342	9,361
less	Asset disposals	–	–	–	–	–	194	–	–	52.10	247
plus	Lost and found assets adjustment	–	–	–	–	–	–	–	–	–	–
plus	Adjustment resulting from asset allocation	–	–	–	–	–	–	–	–	–	–
plus	Asset category transfers	–	–	–	–	–	–	–	–	–	–
	Total closing RAB value	16,932	233	21,201	80,861	38,360	37,806	10,024	4,995	20,665	231,077
	Asset Life										
	Weighted average remaining asset life	49.1	32.1	39.3	45.6	37.2	35.1	26.5	14.8	13.6	(years)
	Weighted average expected total asset life	58.6	45.0	47.8	59.5	48.5	45.1	36.2	16.7	20.6	(years)

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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

5a(i): Regulatory Tax Allowance

				($000)
8		**Regulatory profit / (loss) before tax**		18,974
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	184 *	
12		Amortisation of initial differences in asset values	2,695	
13		Amortisation of revaluations	490	
14				3,369
15				
16	*less*	Total revaluations	1,337	
17		Income included in regulatory profit / (loss) before tax but not taxable	*	
18		Discretionary discounts and customer rebates	6,605	
19		Expenditure or loss deductible but not in regulatory profit / (loss) before tax	– *	
20		Notional deductible interest	4,941	
21				12,884
22				
23		**Regulatory taxable income**		9,459
24				
25	*less*	Utilised tax losses		
26		Regulatory net taxable income		9,459
27				
28		Corporate tax rate (%)	28%	
29		**Regulatory tax allowance**		2,649
30				
31	*	Workings to be provided in Schedule 14		

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).

5a(iii): Amortisation of Initial Difference in Asset Values

				($000)
35				
36		Opening unamortised initial differences in asset values	83,098	
37	*less*	Amortisation of initial differences in asset values	2,695	
38	*plus*	Adjustment for unamortised initial differences in assets acquired		
39	*less*	Adjustment for unamortised initial differences in assets disposed	191	
40		Closing unamortised initial differences in asset values		80,212
41				
42		Opening weighted average remaining useful life of relevant assets (years)		31
43				

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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

5a(iv): Amortisation of Revaluations

sch ref				($000)
44				
45				
46		Opening sum of RAB values without revaluations	214,302	
47				
48		Adjusted depreciation	7,133	
49		Total depreciation	7,623	
50		Amortisation of revaluations		490
51				

5a(v): Reconciliation of Tax Losses

sch ref				($000)
52				
53				
54		**Opening tax losses**		
55	*plus*	Current period tax losses		
56	*less*	Utilised tax losses		
57		**Closing tax losses**		–

5a(vi): Calculation of Deferred Tax Balance

sch ref				($000)
58				
59				
60		**Opening deferred tax**	(9,203)	
61				
62	*plus*	Tax effect of adjusted depreciation	1,997	
63				
64	*less*	Tax effect of tax depreciation	2,535	
65				
66	*plus*	Tax effect of other temporary differences*	4	
67				
68	*less*	Tax effect of amortisation of initial differences in asset values	755	
69				
70	*plus*	Deferred tax balance relating to assets acquired in the disclosure year		
71				
72	*less*	Deferred tax balance relating to assets disposed in the disclosure year	(18)	
73				
74	*plus*	Deferred tax cost allocation adjustment	0	
75				
76		**Closing deferred tax**		(10,473)

77

5a(vii): Disclosure of Temporary Differences

78 *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*
79 *differences).*
80

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

sch ref				($000)
82				
83		**Opening sum of regulatory tax asset values**	100,338	
84	*less*	Tax depreciation	9,052	
85	*plus*	Regulatory tax asset value of assets commissioned	9,361	
86	*less*	Regulatory tax asset value of asset disposals	24	
87	*plus*	Lost and found assets adjustment		
88	*plus*	Adjustment resulting from asset allocation		
89	*plus*	Other adjustments to the RAB tax value		
90		**Closing sum of regulatory tax asset values**		100,623

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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

7 **5b(i): Summary—Related Party Transactions**

		($000)
8	Total regulatory income	
9	Operational expenditure	2,850
10	Capital expenditure	5,311
11	Market value of asset disposals	
12	Other related party transactions	

13 **5b(ii): Entities Involved in Related Party Transactions**

	Name of related party	Related party relationship
15	Counties Power Limited - Field Operations Department	Part of Counties Power run as a separate department and accounted for separately.
16		Performs faults, proactive maintenance and construction services on the Network asset.
17		
18		
19		

20 ** include additional rows if needed*

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	Counties Power Limited - Field Operations Department	Opex	Faults and Reactive	1,369	ID clause 2.3.6(1)(b)
24	Counties Power Limited - Field Operations Department	Opex	Tree Maintenance	623	ID clause 2.3.6(1)(b)
25	Counties Power Limited - Field Operations Department	Opex	Transformer Maintenance	187	ID clause 2.3.6(1)(b)
26	Counties Power Limited - Field Operations Department	Opex	Distribution OH Maintenance	249	ID clause 2.3.6(1)(b)
27	Counties Power Limited - Field Operations Department	Opex	Substation Maintenance	237	ID clause 2.3.6(1)(b)
28	Counties Power Limited - Field Operations Department	Opex	Distribution UG Maintenance	120	ID clause 2.3.6(1)(b)
29	Counties Power Limited - Field Operations Department	Opex	Subtransmission Maintenance	64	ID clause 2.3.6(1)(b)
30	Counties Power Limited - Field Operations Department	Opex	System Automation & Comms	2	ID clause 2.3.6(1)(b)
31	Counties Power Limited - Field Operations Department	Capex	Subtransmission Capital	308	IM clause 2.2.11(5)(g)
32	Counties Power Limited - Field Operations Department	Capex	Construction Lines & Cable	3,291	IM clause 2.2.11(5)(g)
33	Counties Power Limited - Field Operations Department	Capex	Construction Low Voltage Reticulation	1,040	IM clause 2.2.11(5)(g)
34	Counties Power Limited - Field Operations Department	Capex	Substations	136	IM clause 2.2.11(5)(g)
35	Counties Power Limited - Field Operations Department	Capex	Transformers	495	IM clause 2.2.11(5)(g)
36	Counties Power Limited - Field Operations Department	Capex	System Automation & Comms	41	IM clause 2.2.11(5)(g)
37					

38 ** include additional rows if needed*

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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

10 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 Counties Power does not have any qualifying debt									
12									
13									
14									
15									
16 ** include additional rows if needed*						–	–	–	–

17

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

19

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	**Counties Power**
For Year Ended	**31 March 2016**

SCHEDULE 5d: REPORT ON COST ALLOCATIONS

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

sch ref

5d(i): Operating Cost Allocations

	Value allocated ($000s)				
	Arm's length deduction	Electricity distribution services	Non-electricity distribution services	Total	OVABAA allocation increase ($000s)
Service interruptions and emergencies					
Directly attributable		1,707			
Not directly attributable				–	
Total attributable to regulated service		1,707			
Vegetation management					
Directly attributable		1,007			
Not directly attributable				–	
Total attributable to regulated service		1,007			
Routine and corrective maintenance and inspection					
Directly attributable		419			
Not directly attributable				–	
Total attributable to regulated service		419			
Asset replacement and renewal					
Directly attributable		1,137			
Not directly attributable				–	
Total attributable to regulated service		1,137			
System operations and network support					
Directly attributable		1,963			
Not directly attributable				–	
Total attributable to regulated service		1,963			
Business support					
Directly attributable		853			
Not directly attributable		4,479	483	4,962	
Total attributable to regulated service		5,332			
Operating costs directly attributable		7,087			
Operating costs not directly attributable	–	4,479	483	4,962	–
Operational expenditure		11,566			

5d(ii): Other Cost Allocations

Pass through and recoverable costs	($000)
Pass through costs	
Directly attributable	811
Not directly attributable	24
Total attributable to regulated service	836
Recoverable costs	
Directly attributable	10,511
Not directly attributable	
Total attributable to regulated service	10,511

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

Change in cost allocation 1

			($000) CY-1	($000) Current Year (CY)
Cost category	Business support	Original allocation	5,378	5,378
Original allocator or line items	FY15 - Accountancy 100%	New allocation	5,335	5,332
New allocator or line items	FY16 - Accountancy 95%	Difference	43	45

Rationale for change

Change in cost allocation 2

			($000) CY-1	($000) Current Year (CY)
Cost category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–

Rationale for change

Change in cost allocation 3

			($000) CY-1	($000) Current Year (CY)
Cost category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–

Rationale for change

** a change in cost allocation must be completed for each cost allocator change that has occurred in the disclosure year. A movement in an allocator metric is not a change in allocator or component.*

† include additional rows if needed

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

SCHEDULE 5e: REPORT ON ASSET ALLOCATIONS

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

sch ref

5e(i): Regulated Service Asset Values

	Value allocated ($000s) Electricity distribution services
Subtransmission lines	
Directly attributable	16,932
Not directly attributable	
Total attributable to regulated service	16,932
Subtransmission cables	
Directly attributable	233
Not directly attributable	
Total attributable to regulated service	233
Zone substations	
Directly attributable	21,201
Not directly attributable	
Total attributable to regulated service	21,201
Distribution and LV lines	
Directly attributable	80,861
Not directly attributable	
Total attributable to regulated service	80,861
Distribution and LV cables	
Directly attributable	38,360
Not directly attributable	
Total attributable to regulated service	38,360
Distribution substations and transformers	
Directly attributable	37,806
Not directly attributable	
Total attributable to regulated service	37,806
Distribution switchgear	
Directly attributable	10,024
Not directly attributable	
Total attributable to regulated service	10,024
Other network assets	
Directly attributable	4,995
Not directly attributable	
Total attributable to regulated service	4,995
Non-network assets	
Directly attributable	20,370.07
Not directly attributable	295
Total attributable to regulated service	20,665
Regulated service asset value directly attributable	230,782
Regulated service asset value not directly attributable	295
Total closing RAB value	231,077

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

Change in asset value allocation 1

			($000) CY-1	Current Year (CY)
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–

Rationale for change

Change in asset value allocation 2

			($000) CY-1	Current Year (CY)
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–

Rationale for change

Change in asset value allocation 3

			($000) CY-1	Current Year (CY)
Asset category		Original allocation		
Original allocator or line items		New allocation		
New allocator or line items		Difference	–	–

Rationale for change

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

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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

6a(i): Expenditure on Assets

sch ref			($000)	($000)
8		Consumer connection		6,265
9		System growth		3,309
10		Asset replacement and renewal		3,168
11		Asset relocations		0
12		Reliability, safety and environment:		
13		Quality of supply	246	
14		Legislative and regulatory	86	
15		Other reliability, safety and environment	1,172	
16		**Total reliability, safety and environment**		1,503
17		**Expenditure on network assets**		14,245
18		Expenditure on non-network assets		342
19				
20		**Expenditure on assets**		14,587
21	*plus*	Cost of financing		
22	*less*	Value of capital contributions		4,310
23	*plus*	Value of vested assets		
24				
25		**Capital expenditure**		10,276

6a(ii): Subcomponents of Expenditure on Assets (where known)

sch ref		($000)
27	Energy efficiency and demand side management, reduction of energy losses	
28	Overhead to underground conversion	1,098
29	Research and development	

6a(iii): Consumer Connection

sch ref	*Consumer types defined by EDB**	($000)	($000)
32	Urban residential	4,363	
33	Urban commercial	231	
34	Rural residential	1,383	
35	Rural commercial	288	
36			
37	** include additional rows if needed*		
38	**Consumer connection expenditure**		6,265
39			
40	*less* Capital contributions funding consumer connection expenditure	4,310	
41	**Consumer connection less capital contributions**		1,955

6a(iv): System Growth and Asset Replacement and Renewal

sch ref		System Growth ($000)	Asset Replacement and Renewal ($000)
45	Subtransmission	1,195	5
46	Zone substations	391	–
47	Distribution and LV lines	285	1,410
48	Distribution and LV cables	1,394	920
49	Distribution substations and transformers	42	748
50	Distribution switchgear	–	60
51	Other network assets	2	24
52	**System growth and asset replacement and renewal expenditure**	3,309	3,168
53	*less* Capital contributions funding system growth and asset replacement and renewal		
54	**System growth and asset replacement and renewal less capital contributions**	3,309	3,168
55			

6a(v): Asset Relocations

sch ref	*Project or programme**	($000)	($000)
58	Other agency related	0	
59			
60			
61			
62			
63	** include additional rows if needed*		
64	All other projects or programmes - asset relocations		
65	**Asset relocations expenditure**		0
66	*less* Capital contributions funding asset relocations		
67	**Asset relocations less capital contributions**		0
68			

6a(vi): Quality of Supply

sch ref	*Project or programme**	($000)	($000)
71	Voltage quality resolution	246	
72			

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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				
73				
74				
75				
76		** include additional rows if needed*		
77		All other projects programmes - quality of supply		
78		**Quality of supply expenditure**		246
79	*less*	Capital contributions funding quality of supply		
80		**Quality of supply less capital contributions**		246
81		**6a(vii): Legislative and Regulatory**		
82		*Project or programme**	**($000)**	**($000)**
83		Non compliant corrective work	61	
84		Other	25	
85				
86				
87				
88		** include additional rows if needed*		
89		All other projects or programmes - legislative and regulatory		
90		**Legislative and regulatory expenditure**		86
91	*less*	Capital contributions funding legislative and regulatory		
92		**Legislative and regulatory less capital contributions**		86
93		**6a(viii): Other Reliability, Safety and Environment**		
94		*Project or programme**	**($000)**	**($000)**
95		Switch renewal programme	–	
96		Automation programme	355	
97		Safety	367	
98		Other	450	
99				
100		** include additional rows if needed*		
101		All other projects or programmes - other reliability, safety and environment		
102		**Other reliability, safety and environment expenditure**		1,172
103	*less*	Capital contributions funding other reliability, safety and environment		
104		**Other reliability, safety and environment less capital contributions**		1,172
105				
106		**6a(ix): Non-Network Assets**		
107		**Routine expenditure**		
108		*Project or programme**	**($000)**	**($000)**
109		Replacement - Vehicles, Plant, Tools, Computing and Office	342	
110				
111				
112				
113				
114		** include additional rows if needed*		
115		All other projects or programmes - routine expenditure		
116		**Routine expenditure**		342
117		**Atypical expenditure**		
118		*Project or programme**	**($000)**	**($000)**
119		Nil		
120				
121				
122				
123				
124		** include additional rows if needed*		
125		All other projects or programmes - atypical expenditure		
126		**Atypical expenditure**		–
127				
128		**Expenditure on non-network assets**		342

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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

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

sch ref

		($000)	($000)
7	**6b(i): Operational Expenditure**		
8	Service interruptions and emergencies	1,707	
9	Vegetation management	1,007	
10	Routine and corrective maintenance and inspection	419	
11	Asset replacement and renewal	1,137	
12	**Network opex**		4,271
13	System operations and network support	1,963	
14	Business support	5,332	
15	**Non-network opex**		7,295
16			
17	**Operational expenditure**		11,566
18	**6b(ii): Subcomponents of Operational Expenditure (where known)**		
19	Energy efficiency and demand side management, reduction of energy losses		
20	Direct billing*		
21	Research and development		
22	Insurance		267
23	** Direct billing expenditure by suppliers that directly bill the majority of their consumers*		

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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	48,136	48,525	1%
9	**7(ii): Expenditure on Assets**	**Forecast ($000) [2]**	**Actual ($000)**	**% variance**
10	Consumer connection	5,250	6,265	19%
11	System growth	3,986	3,309	(17%)
12	Asset replacement and renewal	4,082	3,168	(22%)
13	Asset relocations	181	0	(100%)
14	Reliability, safety and environment:			
15	Quality of supply	525	246	(53%)
16	Legislative and regulatory	121	86	(29%)
17	Other reliability, safety and environment	1,369	1,172	(14%)
18	**Total reliability, safety and environment**	2,015	1,503	(25%)
19	**Expenditure on network assets**	15,514	14,245	(8%)
20	Expenditure on non-network assets	1,033	342	(67%)
21	Expenditure on assets	16,547	14,587	(12%)
22	**7(iii): Operational Expenditure**			
23	Service interruptions and emergencies	1,371	1,707	25%
24	Vegetation management	1,025	1,007	(2%)
25	Routine and corrective maintenance and inspection	798	419	(47%)
26	Asset replacement and renewal	1,025	1,137	11%
27	**Network opex**	4,220	4,271	1%
28	System operations and network support	1,885	1,963	4%
29	Business support	5,151	5,332	4%
30	**Non-network opex**	7,036	7,295	4%
31	**Operational expenditure**	11,255	11,566	3%
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	1,205	1,098	(9%)
35	Research and development		–	–
36				
37	**7(v): Subcomponents of Operational Expenditure (where known)**			
38	Energy efficiency and demand side management, reduction of energy losses		–	–
39	Direct billing		–	–
40	Research and development	12	–	(100%)
41	Insurance	256	267	4%
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	**Counties Power Ltd**
For Year Ended	**31 March 2016**
/ Sub-Network Name	

SCHEDULE 8: REPORT ON BILLED QUANTITIES AND LINE CHARGE REVENUES

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

sch ref

8(i): Billed Quantities by Price Component

Billed quantities by price component

Consumer group name or price category code	Consumer type or types (eg, residential, commercial etc.)	Standard or non-standard consumer group (specify)	Average no. of ICPs in disclosure year	Energy delivered to ICPs in disclosure year (MWh)	0700-1100	1700-2200	2400-0700	Anytime	Day	Econo	M/W Light	Night	Off Peak	Priority Econo	Peak Saver	Prepay	Summer I	Streetlight	Thrifty Night	Winter Peak	Annual Contract	Export	Demand	Reactive	Supply	Transformer
Price component					0700-1100	1700-2200	2400-0700	Anytime	Day	Econo	M/W Light	Night	Off Peak	Priority Econo	Peak Saver	Prepay	Summer I	Streetlight	Thrifty Night	Winter Peak	Annual Contract	Export	Demand	Reactive	Supply	Transformer
Unit charging basis (eg, days, kW of demand, kVA of capacity, etc.)					kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kVA	kVArh	Day	Day
Business	Commercial	Standard	7,373	95,971	–	–	–	87,076	460	8,179	–	–	–	–	75	–	–	–	181	–	–	21	–	–	2,565	–
3 Rate	Commercial	Standard	124	9,345	–	–	–	–	–	–	–	####	3,586	–	–	–	1,826	–	–	846	–	142	–	–	86	–
Standard Domestic	Residential	Standard	19,763	187,489	–	–	–	136,032	–	49,092	–	893	–	–	395	–	–	–	#####	–	–	517	–	–	7,199	–
Low User Domestic	Residential	Standard	11,523	64,793	–	–	–	45,260	–	19,004	–	–	–	–	298	–	–	–	230	–	–	159	–	–	4,230	–
Prepaid Domestic	Residential	Standard	782	4,109	–	–	–	–	–	–	–	–	–	–	–	4,109	–	–	–	–	–	–	–	–	–	–
Time Of Use	Residential	Standard	157	110,102	22,991	16,554	23,806	379	–	–	–	394	45,480	–	–	–	279	–	–	220	–	–	364	7,268	–	53
Streetlights	Commercial	Standard	18	2,524	–	–	–	–	–	–	242	–	–	–	–	–	–	2,282	–	–	–	–	–	–	–	–
NZS	Industrial	Non-standard	4	42,744	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	42,744	–	–	–	–	–
Watercare	Industrial	Non-standard	1	30,072	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	30,072	–	–	–	–	–
Yashili	Industrial	Non-standard	2	7,582	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7,582	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary																										
		Standard consumer totals	39,740	474,333	22,991	16,554	23,806	268,748	460	76,275	242	####	49,065	–	768	4,109	2,105	2,282	#####	1,067	–	839	364	7,268	14,080	53
		Non-standard consumer totals	7	80,398	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	80,398	–	–	–	–	–
		Total for all consumers	39,747	554,731	22,991	16,554	23,806	268,748	460	76,275	242	####	49,065	–	768	4,109	2,105	2,282	#####	1,067	80,398	839	364	7,268	14,080	53

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

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)	0700-1100	1700-2200	2400-0700	Anytime	Day	Econo	M/W Light	Night	Off Peak	Priority Econo	Peak Saver	Prepay	Summer I	Streetlight	Thrifty Night	Winter Peak	Annual Contract	Export	Demand	Reactive	Supply	Transformer
Price component							0700-1100	1700-2200	2400-0700	Anytime	Day	Econo	M/W Light	Night	Off Peak	Priority Econo	Peak Saver	Prepay	Summer I	Streetlight	Thrifty Night	Winter Peak	Annual Contract	Export	Demand	Reactive	Supply	Transformer
Rate (eg, $ per day, $ per kWh, etc.)							kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kWh	kVA	kVArh	Day	Day
Business	Commercial	Standard	$10,664		$10,664		–	–	–	$8,119	$11	$382	–	–	–	–	$2	–	–	–	$4	–	–	$0	–	–	$2,146	–
3 Rate	Commercial	Standard	$710		$710		–	–	–	–	–	–	–	$67	$249	–	–	–	$199	–	–	$128	–	($0)	–	–	$67	–
Standard Domestic	Residential	Standard	$18,793		$18,793		–	–	–	$12,247	–	$2,215	–	$86	–	–	$10	–	–	–	$27	–	–	$5	–	–	$4,203	–
Low User Domestic	Residential	Standard	$6,851		$6,851		–	–	–	$4,987	–	$1,240	–	–	–	–	$14	–	–	–	$11	–	–	$1	–	–	$598	–
Prepaid Domestic	Residential	Standard	$397		$397		–	–	–	–	–	–	–	–	–	–	–	$397	–	–	–	–	–	–	–	–	–	–
Time Of Use	Residential	Standard	$7,546		$7,546		$919	$1,011	$271	$35	–	–	–	$9	$855	–	–	–	$26	–	–	$36	–	–	$3,388	$366	–	$629
Streetlights	Commercial	Standard	$438		$438		–	–	–	–	–	–	$23	–	–	–	–	–	–	$415	–	–	–	–	–	–	–	–
NZS	Industrial	Non-standard	$1,255		$1,255		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	$1,255	–	–	–	–	–
Watercare	Industrial	Non-standard	$745		$745		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	$745	–	–	–	–	–
Yashili	Industrial	Non-standard	$1,125		$1,125		–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	$1,125	–	–	–	–	–
Add extra rows for additional consumer groups or price category codes as necessary																												
		Standard consumer totals	$45,399	–	$45,399	–	$919	$1,011	$271	$25,389	$11	$3,837	$23	####	$1,104	–	$26	$397	$225	$415	$42	$163	–	$7	$3,388	$366	$7,014	$629
		Non-standard consumer totals	$3,126	–	$3,126	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	$3,126	–	–	–	–	–
		Total for all consumers	$48,525	–	$48,525	–	$919	$1,011	$271	$25,389	$11	$3,837	$23	####	$1,104	–	$26	$397	$225	$415	$42	$163	$3,126	$7	$3,388	$366	$7,014	$629

8(iii): Number of ICPs directly billed

Number of directly billed ICPs at year end 3

Check OK

Company Name	Counties Power
For Year Ended	31 March 2016
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.	25,942	25,937	(5)	3
10	All	Overhead Line	Wood poles	No.	1,516	1,459	(57)	3
11	All	Overhead Line	Other pole types	No.	29	29	–	3
12	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	93	88	(5)	4
13	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	54	72	19	4
14	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	2	2	(0)	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	N/A
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	N/A
23	HV	Zone substation Buildings	Zone substations up to 66kV	No.	6	7	1	4
24	HV	Zone substation Buildings	Zone substations 110kV+	No.	3	3	–	4
25	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	N/A
26	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	17	17	–	4
27	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	39	32	(7)	4
28	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	2	2	–	4
29	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	N/A
30	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	16	12	(4)	4
32	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	85	81	(4)	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	N/A
34	HV	Zone Substation Transformer	Zone Substation Transformers	No.	18	18	–	4
35	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1,481	1,454	(27)	3
36	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	N/A
37	HV	Distribution Line	SWER conductor	km	–	–	–	N/A
38	HV	Distribution Cable	Distribution UG XLPE or PVC	km	157	207	50	3
39	HV	Distribution Cable	Distribution UG PILC	km	29	29	(0)	3
40	HV	Distribution Cable	Distribution Submarine Cable	km	2	2	(0)	4
41	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	101	101	–	3
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	N/A
43	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5,197	4,872	(325)	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.	155	172	17	3
46	HV	Distribution Transformer	Pole Mounted Transformer	No.	3,404	3,150	(254)	3
47	HV	Distribution Transformer	Ground Mounted Transformer	No.	741	769	28	3
48	HV	Distribution Transformer	Voltage regulators	No.	4	4	–	3
49	HV	Distribution Substations	Ground Mounted Substation Housing	No.	705	761	56	3
50	LV	LV Line	LV OH Conductor	km	752	748	(4)	3
51	LV	LV Cable	LV UG Cable	km	553	585	32	3
52	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	30	23	(7)	3
53	LV	Connections	OH/UG consumer service connections	No.	39,214	40,255	1,041	3
54	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	114	148	34	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	33	31	(2)	3
57	All	Load Control	Centralised plant	Lot	5	5	–	4
58	All	Load Control	Relays	No	13,064	3,725	(9,339)	3
59	All	Civils	Cable Tunnels	km	–	–	–	N/A

Company Name	Counties Power
For Year Ended	31 March 2016
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 2016

Number of assets at disclosure year end by installation date

9	Voltage	Asset category	Asset class	Units	pre-1940	1940 –1949	1950 –1959	1960 –1969	1970 –1979	1980 –1989	1990 –1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	No. with age unknown	Items at end of year (quantity)	No. with default dates	Data accuracy (1–4)
10	All	Overhead Line	Concrete poles / steel structure	No.	32	28	273	2,334	3,882	6,648	7,004	263	720	401	286	368	366	456	331	437	536	327	353	275	144	277	133	53	10	25,937	–	3
11	All	Overhead Line	Wood poles	No.	2	2	24	166	279	151	650	35	15	22	8	5	11	18	10	14	12	7	7	3	4	3	6	2	3	1,459	–	3
12	All	Overhead Line	Other pole types	No.	10	–	–	–	10	1	–	–	–	–	–	–	–	–	–	–	2	1	–	–	–	5	–	–	–	29	–	3
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	–	–	–	34	31	8	1	–	–	–	–	14	–	–	–	–	–	–	1	–	–	–	–	–	–	88	–	4
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	3	–	–	–	–	0	21	–	6	–	–	–	–	26	–	–	–	–	–	–	–	10	5	–	–	72	–	4
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	–	–	–	–	–	0	–	–	1	–	–	0	0	–	0	–	–	–	0	–	–	–	–	–	–	2	–	4
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	–	–	1	3	1	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	7	–	4
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	–	–	–	–	–	–	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	–	–	3	–	4
26	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
27	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	–	–	–	–	–	–	9	6	–	–	17	–	4
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	–	–	15	6	5	2	–	4	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	32	–	4
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	–	–	–	–	–	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	2	–	4
30	HV	Zone substation switchgear	33kV RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
31	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
32	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	–	–	1	2	–	4	–	–	–	–	2	1	–	–	–	–	–	–	–	2	–	–	–	–	–	12	–	4
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	–	–	–	10	8	17	13	–	–	–	–	–	–	11	–	–	–	–	–	–	–	22	–	–	–	81	–	4
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
35	HV	Zone Substation Transformer	Zone Substation Transformers	No.	–	–	1	5	2	4	2	–	–	–	–	–	–	2	–	–	–	–	–	–	–	2	–	–	–	18	–	4
36	HV	Distribution Line	Distribution OH Open Wire Conductor	km	40	42	81	221	233	320	269	20	21	28	18	9	12	25	11	8	28	18	13	11	8	8	7	2	–	1,454	–	3
37	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
38	HV	Distribution Line	SWER conductor	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
39	HV	Distribution Cable	Distribution UG XLPE or PVC	km	–	–	–	–	0	2	41	11	8	4	5	7	9	17	12	5	9	14	9	9	9	18	15	1	–	207	–	3
40	HV	Distribution Cable	Distribution UG PILC	km	–	–	0	6	4	8	10	0	0	–	0	–	–	–	0	–	0	0	–	–	–	0	–	0	–	29	–	3
41	HV	Distribution Cable	Distribution Submarine Cable	km	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	0	–	–	–	–	1	–	–	–	2	–	4
42	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	–	–	–	1	–	13	5	3	3	–	1	–	5	2	6	6	8	10	1	10	12	12	2	1	–	101	–	3
43	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
44	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	5	1	21	66	224	566	1,269	216	178	119	132	110	159	64	138	102	108	258	258	212	288	177	162	39	–	4,872	–	3
45	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A
46	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	–	–	–	7	8	12	15	6	2	1	8	2	–	8	8	9	12	13	8	13	7	17	14	2	–	172	–	3
47	HV	Distribution Transformer	Pole Mounted Transformer	No.	5	1	20	30	127	329	654	72	105	70	100	88	106	50	97	54	57	192	222	185	259	154	148	25	–	3,150	–	3
48	HV	Distribution Transformer	Ground Mounted Transformer	No.	–	–	–	6	10	34	154	28	23	21	27	24	27	30	29	33	20	42	47	44	67	47	46	10	–	769	–	3
49	HV	Distribution Transformer	Voltage regulators	No.	–	–	1	–	–	1	–	–	–	–	1	–	–	–	–	–	–	–	–	1	–	–	–	–	–	4	–	3
50	HV	Distribution Substations	Ground Mounted Substation Housing	No.	8	2	17	29	58	37	193	49	24	14	16	14	35	13	16	23	18	30	20	21	51	31	28	4	10	761	–	3
51	LV	LV Line	LV OH Conductor	km	–	–	1	2	3	4	688	7	4	6	4	2	4	2	1	2	5	1	5	1	2	2	1	–	–	748	–	3
52	LV	LV Cable	LV UG Cable	km	–	–	0	1	8	4	225	23	18	21	17	15	33	41	22	14	7	19	11	21	18	37	25	4	0	585	–	3
53	LV	LV Street lighting	LV OH/UG Streetlight circuit	km	–	–	–	–	0	–	0	–	0	0	–	1	0	1	0	1	0	0	1	6	3	2	6	1	–	23	–	3
54	LV	Connections	OH/UG consumer service connections	No.	–	–	–	–	10	12,324	14,981	530	536	595	989	1,034	941	842	890	920	561	589	501	493	722	900	868	1,029	–	40,255	–	3
55	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	–	–	1	10	13	27	16	–	–	–	–	–	–	19	–	–	–	–	–	5	2	55	–	–	–	148	–	3
56	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	1	–	–	–	–	–	1	–	4
57	All	Capacitor Banks	Capacitors including controls	No	–	–	–	–	–	–	23	–	–	–	–	–	–	2	5	–	–	–	–	–	–	1	–	–	–	31	–	3
58	All	Load Control	Centralised plant	Lot	–	–	–	–	–	2	1	–	–	–	–	–	–	1	–	–	–	–	–	–	–	1	–	–	–	5	–	4
59	All	Load Control	Relays	No	–	–	–	–	–	–	401	659	447	336	398	269	178	112	128	68	20	41	61	116	126	55	120	–	190	3,725	–	3
60	All	Civils	Cable Tunnels	km	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	N/A

Company Name	**Counties Power**
For Year Ended	**31 March 2016**
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

		Overhead (km)	Underground (km)	Total circuit length (km)
9				
10	**Circuit length by operating voltage (at year end)**			
11	> 66kV	66	–	66
12	50kV & 66kV	–	–	–
13	33kV	73	1	74
14	SWER (all SWER voltages)	–	–	–
15	22kV (other than SWER)	548	147	695
16	6.6kV to 11kV (inclusive—other than SWER)	927	92	1,019
17	Low voltage (< 1kV)	748	585	1,332
18	**Total circuit length (for supply)**	2,361	824	3,185
19				
20	Dedicated street lighting circuit length (km)	0	23	24
21	Circuit in sensitive areas (conservation areas, iwi territory etc) (km)			8
22				

		Circuit length (km)	(% of total overhead length)
23	**Overhead circuit length by terrain (at year end)**		
24	Urban	108	5%
25	Rural	2,168	92%
26	Remote only	–	–
27	Rugged only	85	4%
28	Remote and rugged	–	–
29	Unallocated overhead lines	–	–
30	**Total overhead length**	2,361	100%
31			

		Circuit length (km)	(% of total circuit length)
32			
33	Length of circuit within 10km of coastline or geothermal areas (where known)	1,628	51%

		Circuit length (km)	(% of total overhead length)
34			
35	Overhead circuit requiring vegetation management	2,361	100%

Company Name	**Counties Power**
For Year Ended	**31 March 2016**

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	Counties Power has no embedded networks		
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	**Counties Power**
For Year Ended	**31 March 2016**
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*

	*Consumer types defined by EDB**	**Number of connections (ICPs)**
10		
11	Urban residential	502
12	Urban commercial	180
13	Rural residential	238
14	Rural commercial	92
15	Industrial (at least 0.5 GWh per annum)	–
16	** include additional rows if needed*	
17	**Connections total**	1,012
18		
19	**Distributed generation**	
20	Number of connections made in year	238 **connections**
21	Capacity of distributed generation installed in year	0.67 **MVA**

22 **9e(ii): System Demand**

23

24

			Demand at time of maximum coincident demand (MW)	
25		**Maximum coincident system demand**		
26		GXP demand	111	
27	*plus*	Distributed generation output at HV and above	4	
28		**Maximum coincident system demand**	115	
29	*less*	Net transfers to (from) other EDBs at HV and above		
30		**Demand on system for supply to consumers' connection points**	115	
31		**Electricity volumes carried**	**Energy (GWh)**	
32		Electricity supplied from GXPs	547	
33	*less*	Electricity exports to GXPs	–	
34	*plus*	Electricity supplied from distributed generation	34	
35	*less*	Net electricity supplied to (from) other EDBs	–	
36		**Electricity entering system for supply to consumers' connection points**	581	
37	*less*	Total energy delivered to ICPs	555	
38		**Electricity losses (loss ratio)**	26	4.5%
39				
40		**Load factor**	0.58	

41 **9e(iii): Transformer Capacity**

		(MVA)
42		
43	Distribution transformer capacity (EDB owned)	316
44	Distribution transformer capacity (Non-EDB owned, estimated)	54
45	**Total distribution transformer capacity**	370
46		
47	**Zone substation transformer capacity**	428

Company Name	**Counties Power**
For Year Ended	**31 March 2016**
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)	164
12 Class C (unplanned interruptions on the network)	200
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**	364

21 **Interruption restoration**	≤3Hrs	>3hrs
22 Class C interruptions restored within	135	65

24 **SAIFI and SAIDI by class**	SAIFI	SAIDI
25 Class A (planned interruptions by Transpower)	–	–
26 Class B (planned interruptions on the network)	0.21	38.13
27 Class C (unplanned interruptions on the network)	3.29	103.47
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**	3.49	141.6

36 **Normalised SAIFI and SAIDI**	Normalised SAIFI	Normalised SAIDI
37 Classes B & C (interruptions on the network)	2.70	118.3

39 **Quality path normalised reliability limit**	SAIFI reliability limit	SAIDI reliability limit
40 SAIFI and SAIDI limits applicable to disclosure year*	N/A	N/A

41 ** not applicable to exempt EDBs*

42 **10(ii): Class C Interruptions and Duration by Cause**

44 **Cause**	SAIFI	SAIDI
45 Lightning	0.27	4.40
46 Vegetation	1.08	25.59
47 Adverse weather	0.07	1.81
48 Adverse environment	–	–
49 Third party interference	0.29	22.53
50 Wildlife	0.25	6.25
51 Human error	–	–
52 Defective equipment	0.60	28.81
53 Cause unknown	0.72	14.08

55 **10(iii): Class B Interruptions and Duration by Main Equipment Involved**

57 **Main equipment involved**	SAIFI	SAIDI
58 Subtransmission lines	–	–
59 Subtransmission cables	–	–
60 Subtransmission other	–	–
61 Distribution lines (excluding LV)	0.15	33.03
62 Distribution cables (excluding LV)	0.05	4.90
63 Distribution other (excluding LV)	0.00	0.20

64 **10(iv): Class C Interruptions and Duration by Main Equipment Involved**

Company Name	**Counties Power**
For Year Ended	**31 March 2016**
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.

	Main equipment involved	**SAIFI**	**SAIDI**
67	Subtransmission lines	0.64	15.80
68	Subtransmission cables	–	–
69	Subtransmission other	0.05	0.43
70	Distribution lines (excluding LV)	2.41	83.45
71	Distribution cables (excluding LV)	0.04	1.34
72	Distribution other (excluding LV)	0.14	2.45

73 10(v): Fault Rate

	Main equipment involved	**Number of Faults**	**Circuit length (km)**	**Fault rate (faults per 100km)**
75	Subtransmission lines	6	139	4.32
76	Subtransmission cables	–	1	–
77	Subtransmission other	1		
78	Distribution lines (excluding LV)	183	1,475	12.41
79	Distribution cables (excluding LV)	4	238	1.68
80	Distribution other (excluding LV)	6		
81	**Total**	200		

Company Name	Counties Power Limited
For Year Ended	31 March 2016

Schedule 14 Mandatory Explanatory Notes

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

2. This schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. Information provided in boxes 1 to 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 subclause 2.7.1(2).

Box 1: Explanatory comment on return on investment

Classification is consistent with previous treatment except that this year's allocation of Accountancy costs to Business Support expenditure has been reduced from 100% to 95% in accordance with clause 2.7.1(2) and the Avoidable Cost Allocation Methodology (ACAM) per clause 2.1.4 of Input Methodologies Determination 2012.

The effect of the reallocation is to reduce the Business Support costs allocated to Operational Expenditure by $45k to $5,332k.

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
As per FY2015, line charge revenue and operational expenditure excludes non-regulated Smart Meters; and Other regulated income includes only standard recoveries relating to the regulated business e.g. Electricity Reserve Market and Other Customer Recoveries related to the Regulatory business that are not Capital Receipts.

There were no reclassified Other regulated income items this 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
No mergers or acquisitions for the regulated business occurred during 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)
RAB asset categories are as per accounting records, except for distribution switchgear which has been extracted from distribution and LV lines, (switches), and from distribution and LV cables, (RMUs). Replacement costs established in 2009 were used for assigning values to the switchgear in the FY2010 and FY2011. Replacement costs established in 2012 were used for assigning values to the switchgear in the FY2012 to FY2016.

There were no reclassified items this year and the method of allocating RAB into the asset categories is as per FY2015.

Assets being disposed of comprise non-system minor plant and equipment ($37k), and transformers sold as scrap ($194k).

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

Items included in permanent differences are the difference between gain/loss on sale of regulatory assets used for the regulatory P&L and the equivalent calculation for tax purposes and non-deductible entertainment expenses and associated GST as they relate to the regulated business, i.e. Loss on disposal disclosure P&L $202.78k; and entertainment expenditure & GST on entertainment expenditure not deductible disclosure P&L $9.57k.

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

There is no income not included in the regulatory profit before tax that is taxable.

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

Included in this value are permanent differences - accounting loss on disposal $193.21k.

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

Included in this value is regulatory asset revaluation of $1,336.64k.

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

Included in this value is permanent difference (gain on sale) of $9.38k.

Regulatory tax allowance: disclosure of temporary differences (5a(vi) of Schedule 5a)

9. In the box below, provide descriptions and workings of material items recorded in the asterisked category 'Tax effect of other temporary differences' in 5a(vi) of Schedule 5a.

Box 6: Tax effect of other temporary differences (current disclosure year)

Temporary differences relate to holiday pay provisions, gratuity and sick leave provisions and doubtful debt provisions as they related to the regulated business. The movement in these provisions has been multiplied by the tax rate to calculate the deferred tax figure.

Holiday Pay (2016) $253.34k (2015) $248.82k, Gratuity & Sick leave Provision (2016) $146.12k (2015) $136.04k, Doubtful Debts (2016) $295.00k (2015) $295.00k.

2016 total $694.45k less 2015 total $679.86k = $14.59 *28%

= $4.09k

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 subclause 2.3.6(1)(b).

Box 7: Related party transactions

Counties Power Limited's related party is the Field Operations division which is wholly owned by Counties Power. The related party tenders for work to the Network division and also performs fault and emergency services on a contractual basis. Charges are made to the Network division for this work only after documentation is signed-off by Network project managers and the documentation is provided to the Finance department.

Analysis has been carried out for the 2012 to 2016 financial years to determine a revenue and expense split within the Field Operations department to confirm that the mark-up percentage for electrical contracting services does not exceed the 17.2% referenced in clause 2.3.6 (1) (b).

From 1 April 2015, charges from the related party have been transferred to Network at cost. Previously, charges from the related party that were capitalised as Network assets included a profit element, and the additions used in the RAB reflected the value after the profit elimination has been applied, as per IM Determination 2.2.11 paragraph 5(g).

The related party component of major projects is primarily normal labour, vehicle and plant costs. Materials on the major projects programs have been sourced by the Field Operations division.

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 subclause 2.7.1(2).

Box 8: Cost allocation

Cost allocations have been calculated using ACAM methodology per the IM Determination. All operating costs except business support, corporate overheads and reception / customer care costs are directly attributable to the regulated services. Business support, corporate overheads and reception / customer care costs have been allocated to regulated and unregulated services using proxy cost allocators such as; Management's estimate of percentage of staff time working on regulated and unregulated services and apportionment of office space utilised for staff conducting regulated and unregulated services.

A small percentage of accountancy costs have been reclassified during the disclosure year as explained in Box 1 above.

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 subclause 2.7.1(2).

Box 9: Commentary on asset allocation

There is only limited shared usage of assets in the non-network assets category.

No items have been reclassified during the disclosure year.

Capital Expenditure for the Disclosure Year (Schedule 6a)

13. In the box below, comment on expenditure on assets 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 subclause 2.7.1(2),

Box 10: Explanation of capital expenditure for the disclosure year

13.1: Consumer types are based on historical AMP descriptions. There were no asset relocations this year.. Treatment for all other categories was to sum the many small projects by significant core drivers.

13.2: Classification is consistent with previous treatment.

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 operational expenditure, as reported in 6b(i) of Schedule 6b;

    14.2 Information on reclassified items in accordance with subclause 2.7.1(2);

    14.3 Commentary on any material atypical expenditure included in operational expenditure disclosed in Schedule 6b, 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

14.1: Assets replaced are typically on the distribution network i.e. pillar boxes, cross arms and poles.

14.2: Classification is consistent with previous treatment.

14.3: There was a significant transformer leak at the Waiuku substation this year ($300k) which has been categorised as Services Interruptions and Emergencies expenditure.

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 subclause 2.7.1(2).

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

(i): The variance between actual and forecast line charge revenue is minimal.

(ii): Variances above 10% listed by category:

- Consumer connection expenditure was 19% above forecast. The variance was due to higher than expected volume of new subdivisions. The forecast was based on previous years average and adjusted for known projects;
- System growth expenditure was 13% below forecast due to completion of the Tuakau 110kV line under budget, carryover of a feeder conversion project due to resource constraints and change in scope, and review of the justification of two feeder reinforcement projects.
- Asset replacement and renewal expenditure was 23% below forecast due to deferral of a voltage regulator installation, deferral of two rehabilitation projects due to review of project justification, and completion of a radio upgrade programme under budget;
- Asset relocations expenditure was Nil compared to forecast of $181k as no agency requests for relocations were received in the year.
- Other reliability, safety and environment expenditure was 25% below forecast due to deferral of a protection upgrade at Pukekohe substation.
- Expenditure on non-network assets was 67% below forecast due to deferral of an IT system upgrade.

(iii): Variances above 10% listed by category:

- Service interruptions and emergencies was 25% unfavourable to forecast due to a significant transformer leak at the Waiuku substation and stormy weather during the year leading to high fault response expenditure.
- Routine and corrective expenditure was 47% below forecast due lower subtransmission maintenance costs and higher capitalisation of maintenance.
- Asset Replacement and Renewal was 11% above forecast due to a one-off transformer refurbishment at Tuakau substation;

(iv): The variance between target and actual overhead to underground conversion expenditure is minimal. Energy efficiency and R&D are not yet measured.

(v): Insurance and R&D expenditure are the only subcomponents of operational expenditure identified and measured. The other items are either not applicable or not separately identified.

Information relating to revenues 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 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

    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

16.1: Target revenue disclosed according to clauses 2.4.1 and 2.4.3(3) $48.1m.

Total billed line charge revenue for the disclosure year, as disclosed in Schedule 8 $48.5m.

16.2: The difference between target and total billed line charge revenue is not material.

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 and SAIFI results are calculated using information from the Company's non-financial systems, which includes the manual recording of some outage types, which affects the completeness of interpretation data, and in some cases the accuracy of installation control point (ICP) numbers included in the SAIDI and SAIFI calculations.

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

Essential equipment is insured under a materials damage policy and this cover is reviewed annually. The material damage cover is for physical loss or damage including earthquake natural disaster cover.

Other than key substations and essential equipment, the bulk of the Network system is not covered by insurance due to the inability to get sufficient cover from the insurance industry for such assets, at an acceptable cost.

Amendments to previously disclosed information

19. 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:

    19.1 a description of each error; and

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

Box 16: Disclosure of amendment to previously disclosed information

There have been no amendments to previously disclosed information pursuant to clause 2.12.1 disclosed in the last 7 years.

Company Name	Counties Power Limited
For Year Ended	31 March 2016

Schedule 15 Voluntary Explanatory Notes

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

There are no voluntary disclosures this year.

Schedule 18 Certification for Year-end Disclosures

Clause 2.9.2

We, Vernon John Dark and Douglas John Troon, being directors of Counties Power 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 Counties Power 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 subclauses 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(1)(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.

In respect of outages, the company is reliant on third parties, in some situations, to notify it of outages. Control over ICP data is also limited. Consequently, there is an inherent limitation in the company's ability to maintain outage records sufficient to ensure complete and accurate disclosure of network reliability statistics. In addition, while historical records have been maintained, requirements under the Electricity Distribution Information Disclosure Determination 2012 specific to clauses 2.5.2(1)(a) and 2.5.2(1)(b) could not have been previously foreseen to have been required and therefore information obtained from the Geospatial Information Systems will not be wholly sufficient for the purposes of Electricity Distribution Information Disclosure Determination 2012.

VJ Dark

DJ Troon

24 August 2016

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Independent Auditors' Report

To the Directors of Counties Power Limited and to the Commerce Commission

The Auditor-General is the auditor of Counties Power Limited (the Company). The Auditor-General has appointed me, Pip Cameron, using the staff and resources of PricewaterhouseCoopers, to provide an opinion, on her behalf, on whether the information disclosed in schedules 1 to 4, 5a to 5g, 6a and 6b, 7, the system average interruption duration index ('SAIDI') and system average interruption frequency index ('SAIFI') information disclosed in Schedule 10 and the explanatory notes in boxes 1 to 12 in Schedule 14 ('the Disclosure Information') for the disclosure year ended 31 March 2016, have been prepared, in all material respects, in accordance with the Electricity Distribution Information Disclosure Determination 2012 (the 'Determination').

Directors' responsibility for the Disclosure Information
The Directors of the Company are responsible for preparation of the Disclosure Information in accordance with the Determination, and for such internal control as the Directors determine is necessary to enable the preparation of the Disclosure Information that is free from material misstatement.

Our responsibility for the Disclosure Information
Our responsibility is to express an opinion on whether the Disclosure Information has been prepared, in all material respects, in accordance with the Determination.

Basis of opinion
We conducted our engagement in accordance with the International Standard on Assurance Engagements (New Zealand) 3000 (Revised) *Assurance Engagements Other Than Audits or Reviews of Historical Financial Information* issued by the External Reporting Board and the Standard on Assurance Engagements 3100: *Compliance Engagements* issued by the External Reporting Board. Copies of these standards are available on the External Reporting Board's website.

These standards require that we comply with ethical requirements and plan and perform our assurance engagement to provide reasonable assurance about whether the Disclosure Information has been prepared in all material respects in accordance with the Determination.

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

We also evaluated:

- the appropriateness of assumptions used and whether they have been consistently applied; and
- the reasonableness of the significant judgements made by the Directors of the Company.

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Independent Auditors' Report

To the Directors of Counties Power Limited and to the Commerce Commission

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

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

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

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

Independence and quality control
When carrying out the engagement, we complied with the Auditor-General's:

- independence and other ethical requirements, which incorporate the independence and ethical requirements of Professional and Ethical Standard 1 (Revised) issued by the New Zealand Auditing and Assurance Standards Board; and

- quality control requirements, which incorporate the quality control requirements of Professional and Ethical Standard 3 (Amended) issued by the New Zealand Auditing and Assurance Standards Board.

We also complied with the independence requirements specified in the Determination.

The Auditor-General, and her employees, and PricewaterhouseCoopers and its partners and employees may deal with the Company on normal terms within the ordinary course of trading activities of the Company. Other than any dealings on normal terms within the ordinary course of business, this engagement and the annual audit of the Company's financial statements, we have no relationship with or interests in the Company.

Qualified Opinion on Schedules 10(i) to 10 (iv)
As described in Box 14 of Schedule 14, there are inherent limitations in the 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 calculations is limited throughout the year.

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Independent Auditors' Report

To the Directors of Counties Power Limited and to the Commerce Commission

There are no practical audit procedures that we could adopt to confirm independently that all the faults and ICP data was properly recorded for the purposes of inclusion in the amounts relating to quality measures set out in Schedules 10(i) to 10(iv). Because of the potential effect of these limitations, we are unable to form an opinion as 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 recorded evidence and explanations that we have required.

In our opinion, except for the matters described above:

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

PricewaterhouseCoopers

Pip Cameron
On behalf of the Auditor-General
Auckland, New Zealand
24 August 2016

PricewaterhouseCoopers