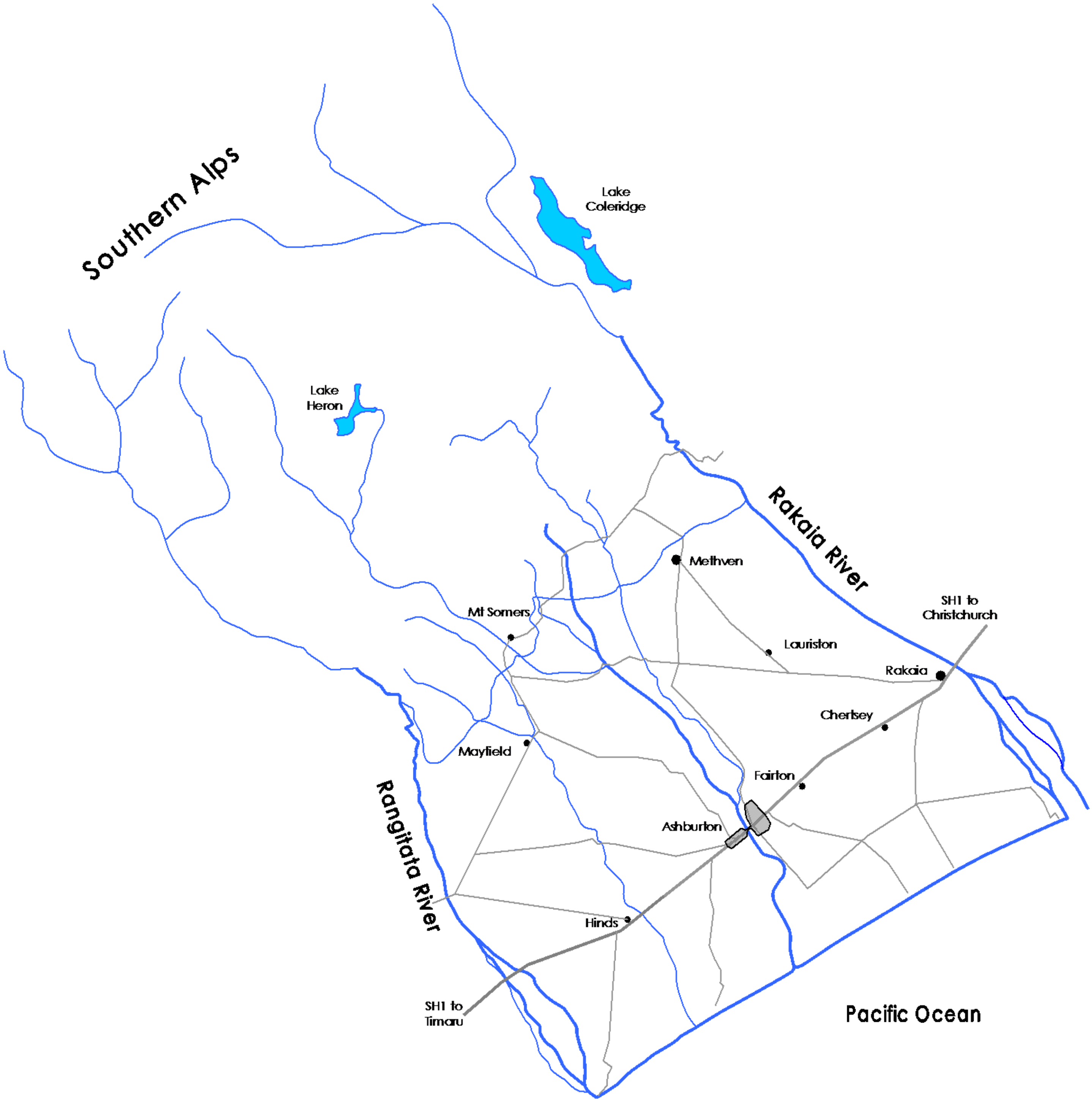
EA NETWORKS ASSET MANAGEMENT PLAN UPDATE 2014-24



ASSET MANAGEMENT PLAN UPDATE
FOR EA NETWORKS' ELECTRICITY NETWORK

Planning Period:	1 April 2014 to 31 March 2024
Disclosure Year:	2014-15
Disclosure Date:	31 March 2014
Approved by Board:	26 March 2014

EA Networks
Private Bag 802
Ashburton 7740

Website: http://www.eanetworks.co.nz
Telephone: (03) 3079800
Facsimile: (03) 3079801

As of November 2012, EA Networks is the trading name of Electricity Ashburton Limited. References to EA Networks in this document denote Electricity Ashburton Limited.

The owner and custodian of this document is the Network Division of EA Networks, Ashburton. All comments, queries and suggestions should be forwarded to the Network Manager.

CONTENTS

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ASSET MANAGEMENT PLAN UPDATE

1 Scope of this Document

In particular disclosure years, the Commerce Commission's Electricity Information Disclosure Determination 2012 allows a distribution lines company to prepare and disclose an Asset Management Plan Update rather than a full Asset Management Plan. The 31 March 2014 disclosure date is one of these occasions when an update is permitted. EA Networks have chosen to issue an Asset Management Plan Update for the 31 March 2014 disclosure date.

This document is the EA Networks 2014-2024 electricity network Asset Management Plan Update. It presumes that the reader has examined the EA Networks 2013-23 Asset Management Plan and it provides incremental information from that plan.

The layout of the document headings follow clause 2.6.4 of the Disclosure Determination.

2 Changes to Network Development Plans

Subtransmission System

The previous AMP/disclosure forecast that the Montalto 66kV zone substation would be built in the 2015-16 financial year. A lack of anticipated load growth in the Montalto area has postponed the need for this development and it has been rescheduled for the 2016-2017 financial year. As a consequence of this delay, the associated 66kV line has been spread over 2015-16 and 2016-17 (previously only 2015-16) as the condition of the existing 33kV line will require a response even if the Montalto 66kV substation is not built.

The delay in Montalto 66kV Zone Substation construction had been anticipated but continuing prospects of gravity pressurised piped irrigation development which could not only postpone additional load but remove existing load, have made the situation quite dynamic. The current Montalto 33kV substation is small and one or two additional large pumps could put it under pressure. In addition to irrigation load there has been interest in utilising the existing irrigation race for generation and this would necessitate Montalto 66kV Zone Substation for full development. The future of this generation development is currently uncertain due to longer-term electricity market prospects. When a final decision is made about piping some of the existing open race schemes, one of several outcomes are likely:

(a) The piping proceeds and no new load occurs and even reduces. Montalto 66kV Zone Substation does not proceed.

(b) The piping proceeds with the need for relatively large booster pumps. Montalto 66kV Zone Substation proceeds because of the new pumping stations.

(c) The piping does not proceed and existing load remains with additional load connecting reasonably quickly. Montalto 66kV Zone Substation proceeds at relatively short notice because of the new irrigation loads.

The exact timetable for a final gravity pressurised piping decision is not known.

Zone Substations

As mentioned above, the Montalto 66kV zone substation has been rescheduled for a year later than previously disclosed (now 2016-17). It is entirely possible that a further delay may occur if sufficient irrigation load does not eventuate.

With the addition of a third 220/66kV transformer at the Transpower Ashburton GXP, it was anticipated that EA Networks' ripple injection facilities were going to provide close to the minimum acceptable signal level. The replacement of at least one ripple injection plant had been scheduled for the 2014-15 financial year. Testing has shown that the signal level is still acceptable and the ripple plant replacements have both been postponed for a year to consider viable alternatives. This now has one ripple plant replaced in 2015-16 and a second one installed in 2016-17 (previously 2015-16).

Two 66kV line bays (ASH and FTN) at Elgin zone substation have been opportunistically incorporated into now completed work. This has reduced the cost of completing this previously planned work at a later date. The remaining costs relate to protection relay procurement and installation during 2016-17 and 2017-18. The timing of the remaining work remains unchanged.

Distribution Network

The delay in Montalto zone substation (see above) causes downstream delays in two distribution projects. The first is the additional overhead and underground 22kV network needed to integrate the Montalto 66kV zone substation into the distribution network. The second is the conversion of the Montalto Hydro station to 22kV (from 33kV) as the 33kV circuit connecting it will be converted to 66kV. Both of these projects have been postponed by one year to coincide with Montalto zone substation construction.

3 Changes to Lifecycle Asset Management Plans

There have been no material changes to the lifecycle management plans during the last year. There are likely to be some changes in the coming year with a new work order management / asset management system being introduced to manage the workflow and processes surrounding asset lifecycles.

4 Reasons for Material Changes to Disclosure Schedules 11a and 11b

There are some generic reasons for material changes to the disclosure schedules while others are more specific.

The most significant generic reason is that of categorisation. The first attempt at categorisation had some confusion between the reason for initiating the work and the outcome of completing the work. These are dramatically different matters and there has been some recategorisation of work as a consequence. The largest impact is in overhead to underground conversion work. Previously this had been categorised as 'Quality of Supply' on the basis of the increased reliability seen once conversion was complete. Unfortunately, this was not the reason for initiating the work. The typical reason EA Networks initiate underground conversion is because the overhead assets have reached the end of their useful life. The correct category is therefore 'Asset Replacement and Renewal'. There are some underground works (not necessarily OH-UG conversion) that fall into different categories.

Other generic reasons are less specific, such as refinement of costs and asset cost categorisation (11a(iii) and 11a(iv)), although these tend not to be of a scale that is as material.

Forecast Capital Expenditure – Schedule 11a

In general, the forecast overall capital expenditure is similar to the previous disclosure. The components of the capital spend have changed predominantly by recategorisation of work.

Asset Replacement and Renewal has increased with the underground conversion work being added to it while Quality of Supply has correspondingly decreased. The delta is about $2M.

The coming year has the prospect of a large amount of subdivision work which has increased the Consumer Connection category and correspondingly the Capital Contribution to that work. It is developer dependant as to whether and when these developments will occur. This work will create the infrastructure for many new connections but, until they are actually used, they will not appear in the EA Networks disclosure as a new connection.

It was not until after the decision was made on the previous disclosure's Consumer Connection categorisation that it was realised that there was no simple way of reporting the costs and capital contributions in those categories. The only pragmatic solution is to use the same categories that EA Networks uses for new connection charging (Urban, Rural LV, Rural Transformer, and Other). Using this data, the job can be categorised and the cost, standard charge and any capital contribution can be accumulated and disclosed. Both new and old categories have been presented in 11a(ii) but the next disclosure will have only the new categories. Forecasts have been completed for the new categories only.

The difficulty with the '*new connection*' is that in many cases the network assets are installed but no connections are immediately made. A subdivision is a case in point. The developer contributes capital -

funding a portion of the reticulation which then vests with EA Networks. Depending on the state of the economy, it may take many years for a significant proportion of the parcels to be developed and a supply taken (new connection established). The year it is developed it will appear as a new connection in Schedule 12c(i). So, although many potential points for connection have been provided, at day one none have been actually connected. Hence it was decided that although large subdivisions are predominantly urban residential, they should be categorised as 'Other' for disclosure purposes.

The opportunity has arisen for several state highway rural overhead renewal projects to be completed as rural underground conversion. EA Networks are negotiating with NZTA for funding to remove the existing pole lines and place them underground. This could see approximately $650k of work completed with the majority funded by NZTA capital contributions. One of the projects is being treated as an Asset Relocation [14026] while the other is Asset Renewal. Another similar 2013-14 project [10032] has been stalled by the Ministry of Primary Industries as the route is covered by a potential exotic plant incursion and no disturbance of the ground is currently permitted.

Atypical Non-Network expenditure is higher in the 2014-15 year to accommodate some significant IT projects [90025] and network billing software.

Forecast Operational Expenditure – Schedule 11b

The overall operational expenditure is broadly in line with the previous disclosure. The future forecasts beyond the coming year show a rise in both categories of Non-Network expenditure which then decrease towards the end of the forecast period. This is a consequence of additional staff being employed to accommodate both the workload and succession planning (more than half of the employees are over 50).

The business support category is significantly larger than previously disclosed. Conversely, the System Operations and Network Support category is much lower than previously disclosed. Combined the two categories are about the same as previously disclosed. The discrepancy appears to have been caused by misallocation of different business activities to the two categories. This has now been resolved and is reflected in the forecast expenditure.

5 Changes to Asset Management Practices

There have been no material changes to asset management practices during the last year that would affect the disclosure of Schedule 13 contents.

As mentioned in section 3 above, a new work order management / asset management system is to be introduced during the coming year. In all likelihood, this system will change some of the methodologies used to manage the electricity assets. A future AMP will detail any changes that are introduced.

6 Disclosure Schedules 11a, 11b, 12a, 12b, 12c, 12d, 14a and 17

EA Networks have chosen not to disclose Schedule 13 as is permitted in the Disclosure Determination.

The disclosed schedules have been completed as at 31 January 2014 and forecasted/scaled to reflect the full 2013-14 disclosure year.

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2014 – 31 March 2024**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)

EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).

This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	4,473	3,763	2,518	2,873	2,436	2,490	2,545	2,601	2,658	2,717	2,776
11	System growth	2,209	3,423	8,739	13,674	9,522	7,130	4,320	5,507	4,512	5,931	3,807
12	Asset replacement and renewal	3,642	4,883	3,409	3,158	3,231	1,934	3,749	3,832	3,916	4,002	4,090
13	Asset relocations	-	431	-	-	-	-	-	-	-	-	-
14	Reliability, safety and environment:											
15	Quality of supply	4,141	1,724	633	2,865	3,066	4,731	1,929	708	724	740	756
16	Legislative and regulatory	-	11	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	267	567	633	649	437	446	456	466	1,593	487	1,664
18	**Total reliability, safety and environment**	4,408	2,303	1,267	3,514	3,503	5,177	2,386	1,174	2,317	1,227	2,420
19	**Expenditure on network assets**	14,732	14,804	15,933	23,218	18,691	16,731	12,999	13,114	13,403	13,876	13,093
20	Non-network assets	980	1,878	602	670	685	678	659	659	659	693	659
21	**Expenditure on assets**	15,712	16,682	16,536	23,888	19,377	17,409	13,658	13,773	14,062	14,569	13,752
22												
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	465	1,417	550	550	500	500	500	500	500	500	500
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	15,247	15,264	15,986	23,338	18,877	16,909	13,158	13,273	13,562	14,069	13,252
28												
29	Value of commissioned assets	15,247	15,264	15,986	23,338	18,877	16,909	13,158	13,273	13,562	14,069	13,252

30		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
	for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
32		**$000 (in constant prices)**										
33	Consumer connection	4,473	3,712	2,425	2,702	2,240	2,240	2,240	2,240	2,240	2,240	2,240
34	System growth	2,209	3,376	8,417	12,860	8,754	6,414	3,802	4,743	3,802	4,891	3,072
35	Asset replacement and renewal	3,642	4,816	3,284	2,970	2,970	2,970	3,300	3,300	3,300	3,300	3,300
36	Asset relocations	-	425	-	-	-	-	-	-	-	-	-
37	Reliability, safety and environment:											
38	Quality of supply	4,141	1,701	610	2,695	2,819	4,256	1,698	610	610	610	610
39	Legislative and regulatory	-	11	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	267	559	610	610	402	402	402	402	1,343	402	1,343
41	**Total reliability, safety and environment**	4,408	2,271	1,220	3,305	3,220	4,657	2,100	1,012	1,953	1,012	1,953
42	**Expenditure on network assets**	14,732	14,599	15,345	21,837	17,184	16,281	11,442	11,295	11,295	11,442	10,564
43	Non-network assets	980	1,852	580	630	630	610	580	580	580	610	580
44	**Expenditure on assets**	15,712	16,451	15,925	22,467	17,814	16,891	12,022	11,875	11,875	12,052	11,144
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
48	Overhead to underground conversion	2,882	2,324	2,278	1,993	1,993	1,993	1,993	1,993	1,993	1,993	1,993
49	Research and development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

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sch ref

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
58		for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
59	**Difference between nominal and constant price forecasts**		**$000**										
60	Consumer connection		-	52	93	171	196	250	305	361	418	477	536
61	System growth		-	47	323	813	768	716	517	764	710	1,040	735
62	Asset replacement and renewal		-	67	126	188	261	(1,036)	449	532	616	702	790
63	Asset relocations		-	6	-	-	-	-	-	-	-	-	-
64	Reliability, safety and environment:												
65	Quality of supply		-	24	23	170	247	475	231	98	114	130	146
66	Legislative and regulatory		-	0	-	-	-	-	-	-	-	-	-
67	Other reliability, safety and environment		-	8	23	39	35	45	55	65	251	85	321
68	**Total reliability, safety and environment**		-	32	47	209	282	520	286	163	364	215	467
69	**Expenditure on network assets**		-	204	588	1,381	1,507	450	1,557	1,819	2,108	2,434	2,529
70	Non-network assets		-	26	22	40	55	68	79	79	79	83	79
71	**Expenditure on assets**		-	230	611	1,421	1,563	518	1,636	1,898	2,187	2,517	2,608
72													

sch ref			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
73		for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
74	**11a(ii): Consumer Connection**							
75	*Consumer types defined by EDB**		**$000 (in constant prices)**					
76	General		3,788	-	-	-	-	-
77	Irrigation		582	-	-	-	-	-
78	Industrial		103	-	-	-	-	-
	Urban		-	164	150	150	140	140
79	Rural LV		-	574	525	525	500	500
	Rural Transformer		-	1,367	1,250	1,250	1,150	1,150
80	Other (including large subdivisions)		-	1,607	500	777	450	450
81	**include additional rows if needed*							
82	**Consumer connection expenditure**		4,473	3,712	2,425	2,702	2,240	2,240
83	*less* Capital contributions funding consumer connection		465	1,067	550	550	500	500
84	**Consumer connection less capital contributions**		4,008	2,644	1,875	2,152	1,740	1,740

sch ref							
85	**11a(iii): System Growth**						
86	Subtransmission	1,225	-	2,185	4,909	-	753
87	Zone substations	681	-	2,797	2,210	4,268	1,453
88	Distribution and LV lines	67	552	1,079	2,208	972	972
89	Distribution and LV cables	123	346	801	1,349	1,349	1,349
90	Distribution substations and transformers	3	1,892	1,254	1,254	1,254	1,254
91	Distribution switchgear	111	9	201	831	811	533
92	Other network assets		577	100	100	100	100
93	**System growth expenditure**	2,209	3,376	8,417	12,860	8,754	6,414
94	*less* Capital contributions funding system growth	-	-	-	-	-	-
95	**System growth less capital contributions**	2,209	3,376	8,417	12,860	8,754	6,414

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sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
104		for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
105	**11a(iv): Asset Replacement and Renewal**		**$000 (in constant prices)**					
106		Subtransmission	1,095	838	-	-	-	-
107		Zone substations	75	359	-	-	-	-
108		Distribution and LV lines	958	1,107	743	743	743	743
109		Distribution and LV cables	9	1,631	2,049	1,782	1,782	1,782
110		Distribution substations and transformers	1,483	152	344	297	297	297
111		Distribution switchgear	22	729	149	149	149	149
112		Other network assets	-	-	-	-	-	-
113		**Asset replacement and renewal expenditure**	3,642	4,816	3,284	2,970	2,970	2,970
114	*less*	Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
115		**Asset replacement and renewal less capital contributions**	3,642	4,816	3,284	2,970	2,970	2,970
116	**11a(v):Asset Relocations**							
117		*Project or programme**						
118		Methven 66kV UG	-	-	-	-	-	-
119		[14026] Works Road to Dromore Corner	-	370	-	-	-	-
120		[14035] SH1 & Walnut Ave Intersectn Re-Design (Re-locate Sub)	-	55	-	-	-	-
122			-	-	-	-	-	-
123		**include additional rows if needed*						
124		All other asset relocations projects or programmes	-	-	-	-	-	-
125		**Asset relocations expenditure**	-	425	-	-	-	-
126	*less*	Capital contributions funding asset relocations	-	350	-	-	-	-
127		**Asset relocations less capital contributions**	-	75	-	-	-	-
128								
129	**11a(vi):Quality of Supply**							
130		*Project or programme**						
131		[10020] Dobson Street, Chalmers Ave to Willow Street UG	130	-	-	-	-	-
		[10009] Digbys Bridge 11kV (4km)	6	-	-	-	-	-
		[10088] Additional RMUs	380	-	-	-	-	-
		[10022] Dolma Street, Methven UG - see [14013] below	19	-	-	-	-	-
		[10023] Carters Terrace, Grove Street UG	50	-	-	-	-	-
		[10024] 64 Middle Road to Belt Road UG	1	-	-	-	-	-
		[10028] Chalmers Ave/Nelson St, Havelock St to Eaton St UG	289	-	-	-	-	-
		[10029] Hoods Rd/Pattons Rd/Ash Gorge Rd, Mt Somers UG	950	-	-	-	-	-
		[10030] Wellington St, Havelock St, Tancred St UG	346	-	-	-	-	-
		[10032] Methven Highway UG	-	-	-	-	-	-
		[10080] Methven 10MVA 11/22kV Transformer	316	-	-	-	-	-
		[10025] Albert Street - Adam Street UG	-	-	-	-	-	-
		[13010] Install 8* Ringmain switches exist O/H Systems	-	582	-	-	-	-
		[13011] Install 5* Ringmain switches new U/G projects	-	312	-	-	-	-
		[13017] Janitza Harmonic Recorders	-	13	-	-	-	-
		[13115] Replace/Reposition available NULEC *3	-	12	-	-	-	-
		[14013] Dolma Street Methven UG [Carry over from 2013-2014]	-	318	-	-	-	-
		[14018] Rakaia 22kV Security. Railway Tce East to Mackie St 31	-	159	-	-	-	-
		[14040] 11kV Reconfiguration Morgan St & Alington St Methven	-	11	-	-	-	-

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sch ref								
		[15010] Lauriston ZSS Line Diff, BZ & TX Protection	-	38	-	-	-	-
		[15025] Elgin ZSS Line Diff Protection	-	38	-	-	-	-
		[15030] Wakanui ZSS Line Diff and BZ Protection	-	59	-	-	-	-
		[15035] Overdale ZSS Line Diff and BZ Protection	-	62	-	-	-	-
		[15040] Methven ZSS Line Diff and BZ Protection	-	80	-	-	-	-
		[15045] HBK System Synchronising	-	17	-	-	-	-
		[10062] EGN New 66kV Ripple Plant #2 (inc Bay)	-	-	-	996	-	-
		[10066] HTH ZSS Second Transformer	-	-	-	1,088	-	-
		[10060] LSN ZSS Second Transformer	-	-	-	-	1,174	-
		[10065] TIN New 66kV Switching Station	-	-	-	-	1,035	-
132		[10068] CRW & MON New Line Bays	-	-	-	-	-	454
133		[10045] OVD ZSS Second Transformer	-	-	-	-	-	1,088
134		[10067] CRW-MON New 66kV Line (20 km)	-	-	-	-	-	2,104
135			-	-	-	-	-	-
136		**include additional rows if needed*						
137		All other quality of supply projects or programmes	1,655	-	610	610	610	610
138		**Quality of supply expenditure**	4,141	1,701	610	2,695	2,819	4,256
139	*less*	Capital contributions funding quality of supply	-	-	-	-	-	-
140		**Quality of supply less capital contributions**	4,141	1,701	610	2,695	2,819	4,256
141								

142 **11a(vii): Legislative and Regulatory**

143		*Project or programme**						
144		[13016] AUFALS Implementation	-	11	-	-	-	-
148			-	-	-	-	-	-
149		**include additional rows if needed*						
150		All other legislative and regulatory projects or programmes	-	-	-	-	-	-
151		**Legislative and regulatory expenditure**	-	11	-	-	-	-
152	*less*	Capital contributions funding legislative and regulatory	-	-	-	-	-	-
153		**Legislative and regulatory less capital contributions**	-	11	-	-	-	-
161								

			Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
162		for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
163		**11a(viii): Other Reliability, Safety and Environment**						
164		*Project or programme**	**$000 (in constant prices)**					
165		[90009] - Other Reliability, Safety and Environment	267	332	-	-	-	-
166		[16003] Substation Security (Access Control Only)	-	73	-	-	-	-
167		[16004] Substation Surveillance Only	-	59	-	-	-	-
168		[13014] New, upgrade Earthing sys conv & swgr	-	71	-	-	-	-
169			-	-	-	-	-	-
170		**include additional rows if needed*						
171		All other reliability, safety and environment projects or programmes	-	24	610	610	402	402
172		**Other reliability, safety and environment expenditure**	267	559	610	610	402	402
173	*less*	Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
174		**Other reliability, safety and environment less capital contributions**	267	559	610	610	402	402
175								
176								
177								

Company Name	**Electricity Ashburton Limited**
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SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

This schedule requires a breakdown of forecast expenditure on assets for the current disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms. Also required is a forecast of the value of commissioned assets (i.e., the value of RAB additions)
EDBs must provide explanatory comment on the difference between constant price and nominal dollar forecasts of expenditure on assets in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref							
178	**11a(ix): Non-Network Assets**						
179	**Routine expenditure**						
180	*Project or programme**						
181	Plant	53	-	80	80	80	80
182	Vehicles	71	115	150	150	150	150
183	Information Technology	-	83	100	100	100	100
184	Carried Forward - Vehicles	-	110	-	-	-	-
185		-	-	-	-	-	-
186	**include additional rows if needed*						
187	All other routine expenditure projects or programmes	-	40	-	-	-	-
188	**Routine expenditure**	124	348	330	330	330	330
189	**Atypical expenditure**						
190	*Project or programme**						
191	New Building	133	-	-	-	-	-
	GIS Project / IT Projects	-	-	-	-	-	-
	Aerial Photography	-	-	-	-	-	30
	Network Billing Software	-	111	-	-	-	-
192	Radio Telephone Upgrade	426	-	-	-	-	-
193	LAN Upgrade	269	-	-	-	-	-
194	Corporate Branding	-	-	-	-	-	-
	Financial System Upgrade	-	-	-	-	-	-
	[99016] Back-up Control Facilities at ex-Methven33 Substation	-	111	-	-	-	-
	[90025] Asset/Works Management Software	-	554	-	-	-	-
	[13024] GPS Vehicle Management, Radio Access, Dispatching	-	74	-	-	-	-
	IT - Field Mobility	-	-	-	50	50	
	Carried Forward - Asset/Works Management Software	-	250	-	-	-	-
	Carried Forward - GIS Electrical Implementation	-	250	-	-	-	-
	Carried Forward - Other	-	40	-	-	-	-
195		-	-	-	-	-	-
196	**include additional rows if needed*						
197	All other atypical projects or programmes	28	114	250	250	250	250
198	**Atypical expenditure**	856	1,504	250	300	300	280
199							
200	**Non-network assets expenditure**	980	1,852	580	630	630	610

Company Name	**Electricity Ashburton Limited**
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SCHEDULE 11b: REPORT ON FORECAST OPERATIONAL EXPENDITURE

This schedule requires a breakdown of forecast operational expenditure for the disclosure year and a 10 year planning period. The forecasts should be consistent with the supporting information set out in the AMP. The forecast is to be expressed in both constant price and nominal dollar terms.
EDBs must provide explanatory comment on the difference between constant price and nominal dollar operational expenditure forecasts in Schedule 14a (Mandatory Explanatory Notes).
This information is not part of audited disclosure information.

sch ref		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
8	for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	993	722	758	772	786	799	813	827	841	855	869
11	Vegetation management	248	265	291	307	323	324	324	325	325	326	326
12	Routine and corrective maintenance and inspection	575	604	619	637	655	673	691	709	729	748	769
13	Asset replacement and renewal	592	721	738	757	776	794	813	832	851	871	892
14	**Network Opex**	2,409	2,312	2,406	2,473	2,540	2,589	2,640	2,692	2,746	2,800	2,856
15	System operations and network support	2,127	2,538	2,703	2,874	2,940	3,005	2,954	2,903	2,848	2,911	2,975
16	Business support	3,719	4,224	4,325	4,406	4,485	4,561	4,638	4,716	4,796	4,877	4,959
17	**Non-network opex**	5,846	6,762	7,027	7,280	7,425	7,566	7,592	7,619	7,644	7,787	7,934
18	**Operational expenditure**	8,255	9,074	9,433	9,753	9,965	10,155	10,232	10,311	10,390	10,588	10,790

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20	for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	993	712	730	726	723	719	716	712	708	705	701
23	Vegetation management	248	261	280	288	297	291	285	280	274	269	263
24	Routine and corrective maintenance and inspection	575	596	596	599	602	605	608	611	614	617	620
25	Asset replacement and renewal	592	711	711	712	713	714	715	716	717	718	720
26	**Network Opex**	2,409	2,280	2,317	2,326	2,335	2,329	2,324	2,319	2,314	2,309	2,304
27	System operations and network support	2,127	2,503	2,603	2,703	2,703	2,703	2,600	2,500	2,400	2,400	2,400
28	Business support	3,719	4,165	4,165	4,144	4,123	4,103	4,082	4,062	4,042	4,021	4,001
29	**Non-network opex**	5,846	6,668	6,768	6,847	6,826	6,806	6,682	6,562	6,442	6,421	6,401
30	**Operational expenditure**	8,255	8,948	9,085	9,173	9,161	9,135	9,006	8,881	8,755	8,730	8,706
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
34	Direct billing*	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35	Research and Development	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
36	Insurance	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
40	for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**	**31 Mar 20**	**31 Mar 21**	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	10	28	46	63	80	97	115	132	150	168
43	Vegetation management	-	4	11	18	26	32	39	45	51	57	63
44	Routine and corrective maintenance and inspection	-	8	23	38	53	68	83	98	115	131	149
45	Asset replacement and renewal	-	10	27	45	63	80	97	115	134	153	172
46	**Network Opex**	-	32	89	147	205	260	316	374	432	491	552
47	System operations and network support	-	35	100	171	237	302	354	403	448	511	575
48	Business support	-	58	160	262	362	458	556	654	754	856	958
49	**Non-network opex**	-	93	259	433	599	760	909	1,057	1,202	1,366	1,533
50	**Operational expenditure**	-	125	348	580	804	1,020	1,226	1,431	1,634	1,857	2,084

Company Name	**Electricity Ashburton Limited**
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SCHEDULE 12a: REPORT ON ASSET CONDITION

This schedule requires a breakdown of asset condition by asset class as at the start of the forecast year. The data accuracy assessment relates to the percentage values disclosed in the asset condition columns. Also required is a forecast of the percentage of units to be replaced in the next 5 years. All information should be consistent with the information provided in the AMP and the expenditure on assets forecast in Schedule 11a. All units relating to cable and line assets, that are expressed in km, refer to circuit lengths.

sch ref

sch ref	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
7					**Asset condition at start of planning period (percentage of units by grade)**						
10	All	Overhead Line	Concrete poles / steel structure	No.	6.22%	2.96%	67.41%	23.41%	-	2	7.70%
11	All	Overhead Line	Wood poles	No.	5.35%	6.02%	31.97%	56.66%	-	2	8.36%
12	All	Overhead Line	Other pole types	No.	22.22%	22.22%	33.33%	22.22%	-	2	33.33%
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	0.66%	2.95%	25.33%	71.05%	-	3	2.14%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	[Select one]	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	68.70%	31.30%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	[Select one]	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	[Select one]	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	[Select one]	-
19	HV	Subtransmission Cable	Subtransmission UG 110kV+ (XLPE)	km	-	-	-	-	-	[Select one]	-
20	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Oil pressurised)	km	-	-	-	-	-	[Select one]	-
21	HV	Subtransmission Cable	Subtransmission UG 110kV+ (Gas Pressurised)	km	-	-	-	-	-	[Select one]	-
22	HV	Subtransmission Cable	Subtransmission UG 110kV+ (PILC)	km	-	-	-	-	-	[Select one]	-
23	HV	Subtransmission Cable	Subtransmission submarine cable	km	-	-	-	-	-	[Select one]	-
24	HV	Zone substation Buildings	Zone substations up to 66kV	No.	-	-	9.52%	90.48%	-	2	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	[Select one]	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	[Select one]	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	65.00%	35.00%	-	-	2	32.50%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	2	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	10.10%	7.07%	68.69%	14.14%	-	3	13.64%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	[Select one]	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	[Select one]	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	-	100.00%	-	2	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	3.38%	11.39%	85.23%	-	2	1.69%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	2.78%	27.78%	22.22%	47.22%	-	2	16.67%

sch ref	Voltage	Asset category	Asset class	Units	Grade 1	Grade 2	Grade 3	Grade 4	Grade unknown	Data accuracy (1–4)	% of asset forecast to be replaced in next 5 years
42					**Asset condition at start of planning period (percentage of units by grade)**						
45	HV	Zone Substation Transformer	Zone Substation Transformers	No.	3.57%	10.71%	14.29%	71.43%	-	3	8.93%
46	HV	Distribution Line	Distribution OH Open Wire Conductor	km	3.59%	4.77%	34.34%	57.30%	-	3	5.97%
47	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	[Select one]	-
48	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	[Select one]	-
49	HV	Distribution Cable	Distribution UG XLPE or PVC	km	-	0.69%	25.73%	73.57%	-	3	0.35%
50	HV	Distribution Cable	Distribution UG PILC	km	4.38%	40.26%	45.29%	10.07%	-	1	24.51%
51	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	[Select one]	-
52	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	100.00%	-	-	2	-
53	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	[Select one]	-
54	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	2.37%	2.12%	11.39%	84.12%	-	2	3.43%
55	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	[Select one]	-
56	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	0.50%	2.48%	27.05%	69.98%	-	3	1.74%
57	HV	Distribution Transformer	Pole Mounted Transformer	No.	7.06%	13.95%	22.55%	56.44%	-	3	14.04%
58	HV	Distribution Transformer	Ground Mounted Transformer	No.	4.10%	6.94%	16.47%	72.49%	-	3	7.57%
59	HV	Distribution Transformer	Voltage regulators	No.	-	100.00%	-	-	-	3	50.00%
60	HV	Distribution Substations	Ground Mounted Substation Housing	No.	0.45%	4.90%	29.18%	65.48%	-	2	2.90%
61	LV	LV Line	LV OH Conductor	km	21.78%	18.75%	38.64%	20.82%	-	3	31.16%
62	LV	LV Cable	LV UG Cable	km	0.99%	2.65%	37.36%	59.00%	-	3	2.32%
63	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	6.42%	5.61%	39.19%	48.79%	-	2	9.22%
64	LV	Connections	OH/UG consumer service connections	No.	-	33.33%	33.33%	33.34%	-	3	16.67%
65	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	6.67%	13.33%	80.00%	-	2	3.33%
66	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	100.00%	-	3	-
67	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	[Select one]	-
68	All	Load Control	Centralised plant	Lot	66.67%	33.33%	-	-	-	3	83.33%
69	All	Load Control	Relays	No.	-	-	-	-	-	[Select one]	-
70	All	Civils	Cable Tunnels	km	-	-	-	-	-	[Select one]	-

Company Name	**Electricity Ashburton Limited**
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SCHEDULE 12b: REPORT ON FORECAST CAPACITY

This schedule requires a breakdown of current and forecast capacity and utilisation for each zone substation and current distribution transformer capacity. The data provided should be consistent with the information provided in the AMP. Information provided in this table should relate to the operation of the network in its normal steady state configuration.

sch ref

7 **12b(i): System Growth - Zone Substations**

sch ref	*Existing Zone Substations*	Current Peak Load (MVA)	Installed Firm Capacity (MVA)	Security of Supply Classification (type)	Transfer Capacity (MVA)	Utilisation of Installed Firm Capacity %	Installed Firm Capacity +5 years (MVA)	Utilisation of Installed Firm Capacity + 5yrs %	Installed Firm Capacity Constraint +5 years (cause)	Explanation
8										
9	Ashburton 33/11kV [ASH]	24	20	N-1 switched	28	120%	20	94%	No constraint within +5 years	Firm capacity limit is N-1 transformer capacity limit. Additional 11kV cables in Ashburton increase fast transfer capacity from NTN. 20 MVA hot stand-by available from ASH 66/11kV substation.
	Ashburton 66/11kV [ASH]	-	-	N-1 switched	28	-	20	94%	No constraint within +5 years	Within 5 years the ASH 33/11kV substation will be the ASH 66/11 kV substation. All load will be served from the 66kV network. A combination of steady state load transfer to NTN and additional fast transfer switched capacity will ensure acceptable security.
10	Carew 66/22kV [CRW]	12	-	N	9	-	-	-	Transformer	A second transformer would provide 100% firm capacity. Transfer capacity increases with additional 22kV conversion.
11	Coldstream 66/22kV [CSM]	12	-	N	9	-	20	64%	No constraint within +5 years	A second transformer provides 100% firm capacity.
12	Dorie 66/22kV [DOR]	10	-	N	9	-	-	-	Transformer	A second transformer would provide 100% firm capacity.
13	Eiffelton 66/11kV [EFN]	8	-	N	4	-	-	-	Transformer	A second transformer would provide 100% firm capacity. Transfer capacity increases with additional 22kV conversion.
14	Fairton 33/11kV [FTN]	8	10	N-1 switched	6	78%	20	43%	No constraint within +5 years	New substation provides 100% firm capacity. Transfer capacity increases with additional 22kV conversion.
15	Hackthorne 66/22kV [HTH]	13	-	N	9	-	20	73%	No constraint within +5 years	capacity increases with additional 22kV conversion and 66kV MSM and MON.
16	Highbank 66/11kV [HBK]	7	-	N	-	-	-	-	Other	Owned by Trustpower. Winter:generation. Summer:pump load.
17	Lagmhor 66/22kV [LGM]	5	-	N	5	-	-	-	Transformer	A second transformer would provide 100% firm capacity. Transfer capacity increases with additional 22kV conversion and lines.
18	Lauriston 66/22kV [LSN]	14	-	N	7	-	20	79%	No constraint within +5 years	capacity increases with additional 22kV conversion and MTV 22kV supply.
19	Methven 33/11kV [MVN]	2	-	N	4	-	-	-	No constraint within +5 years	Decommissioned and merged with Methven 66/11kV substation.
20	Methven 66/11kV [MTV]	4	-	N	4	-	-	-	Transformer	A second transformer would provide 100% firm capacity. Transfer capacity increases with additional 22kV conversion.
21	Methven 66/33kV [MTV]	5	-	N	5	-	-	-	No constraint within +5 years	33/11-22kV load is converted to 66/11-22kV alleviating constraint.
22	Mt Somers 33/11kV [MSM]	3	-	N	3	-	-	-	Transformer	A second transformer would provide 100% firm capacity. Transfer capacity increases with additional 22kV conversion.
23	Mt Hutt 33/11kV [MHT]	2	-	N	2	-	-	-	Transformer	A second transformer would provide 100% firm capacity. Transfer capacity increases with additional 22kV conversion.
24	Montalto 33/11kV [MON]	1	-	N	1	-	-	-	Transformer	A second transformer would provide 100% firm capacity. Conversion to 66/22kV and 22kV conversion increases transfer
25	Northtown 33/11kV [NTN]	9	10	N-1	8	89%	20	93%	No constraint within +5 years	33kV to 66kV conversion doubles transformer rating. Additional 11kV cables in Ashburton increase fast transfer capacity from ASH.
26	Overdale 66/22kV [OVD]	13	-	N	10	-	-	-	Transformer	A second transformer would provide 100% firm capacity. Transfer capacity increases with additional 22kV conversion.
27	Pendarves 66/22kV [PDS]	15	20	N-1	10	77%	20	80%	No constraint within +5 years	Firm capacity limit is N-1 transformer capacity limit.
	Seafield 33/11kV [SFD]	9	-	N	5		-	-	Transformer	A second transformer would provide 100% firm capacity. Negotiated security with sole industrial customer.
28	Wakanui 66/22kV [WNU]	12	-	N	10	-	-	-	Transformer	A second transformer would provide 100% firm capacity. Elgin 66/22kV conversion increases 22kV transfer capacity significantly.

29 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

30 **12b(ii): Transformer Capacity**

sch ref		(MVA)
31		**(MVA)**
32	Distribution transformer capacity (EDB owned)	N/A
33	Distribution transformer capacity (Non-EDB owned)	N/A
34	**Total distribution transformer capacity**	#VALUE!
35		
36	**Zone substation transformer capacity**	N/A

Company Name	**Electricity Ashburton Limited**
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SCHEDULE 12C: REPORT ON FORECAST NETWORK DEMAND

This schedule requires a forecast of new connections (by consumer type), peak demand and energy volumes for the disclosure year and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumptions used in developing the expenditure forecasts in Schedule 11a and Schedule 11b and the capacity and utilisation forecasts in Schedule 12b.

sch ref

7 12c(i): Consumer Connections

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
8	*Number of ICPs connected in year by consumer type*		**Number of connections**					
9			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10		for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
11	*Consumer types defined by EDB**							
12	General [Old Category]		225	-	-	-	-	-
13	Irrigation [Old Category]		20	-	-	-	-	-
14	Industrial [Old Category]		1	-	-	-	-	-
	Urban		-	50	55	60	55	55
15	Rural LV		-	75	75	75	70	70
	Rural Transformer		-	125	120	115	110	110
16	Other		-	-	-	-	-	-
17	**Connections total**		246	250	250	250	235	235
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		25	37	49	61	73	85
21	Installed connection capacity of distributed generation (MVA)		28	28	28	28	28	29

22 12c(ii) System Demand

sch ref				Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
23				*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
24		**Maximum coincident system demand (MW)**	for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
25		GXP demand		165	167	171	173	174	175
26	*plus*	Distributed generation output at HV and above		1	1	1	1	1	1
27		**Maximum coincident system demand**		166	168	172	174	175	176
28	*less*	Net transfers to (from) other EDBs at HV and above		-	-	-	-	-	-
29		**Demand on system for supply to consumers' connection points**		166	168	172	174	175	176
30		**Electricity volumes carried (GWh)**							
31		Electricity supplied from GXPs		522	534	546	558	570	583
32	*less*	Electricity exports to GXPs		22	22	21	21	20	20
33	*plus*	Electricity supplied from distributed generation		103	103	103	103	103	103
34	*less*	Net electricity supplied to (from) other EDBs		-	-	-	-	-	-
35		**Electricity entering system for supply to ICPs**		603	615	628	640	653	666
36	*less*	Total energy delivered to ICPs		565	576	588	600	612	624
37		**Losses**		38	39	40	40	41	42
38									
39		**Load factor**		41%	42%	42%	42%	43%	43%
40		**Loss ratio**		6.3%	6.3%	6.4%	6.3%	6.3%	6.3%

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2014 – 31 March 2024**
Network / Sub-network Name	**Electricity Ashburton Limited**

SCHEDULE 12d: REPORT FORECAST INTERRUPTIONS AND DURATION

This schedule requires a forecast of SAIFI and SAIDI for disclosure and a 5 year planning period. The forecasts should be consistent with the supporting information set out in the AMP as well as the assumed impact of planned and unplanned SAIFI and SAIDI on the expenditures forecast provided in Schedule 11a and Schedule 11b.

sch ref								
8			*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
9		for year ended	**31 Mar 14**	**31 Mar 15**	**31 Mar 16**	**31 Mar 17**	**31 Mar 18**	**31 Mar 19**
10	**SAIDI**							
11	Class B (planned interruptions on the network)		69.4	73.0	73.0	73.0	73.0	73.0
12	Class C (unplanned interruptions on the network)		820.5	127.0	127.0	127.0	127.0	127.0
13	**SAIFI**							
14	Class B (planned interruptions on the network)		0.25	0.26	0.26	0.26	0.26	0.26
15	Class C (unplanned interruptions on the network)		2.91	1.46	1.46	1.46	1.46	1.46

Schedule 14a Mandatory Explanatory Notes on Forecast Information

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

2. This Schedule is mandatory—EDBs must provide the explanatory comment specified below, in accordance with clause 2.7.1. This information is not part of the audited disclosure information, and so is not subject to the assurance requirements specified in section 2.8.

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

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

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

The difference is 1.4%. This is the 2015 CPI Forecast by the New Zealand Government Treasury published on 17th December 2013.
(http://www.treasury.govt.nz/budget/forecasts/hyefu2013)

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

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

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

The difference is 1.4%. This is the 2015 CPI Forecast by the New Zealand Government Treasury published on 17th December 2013.
(http://www.treasury.govt.nz/budget/forecasts/hyefu2013)

EA Networks considers the answers given for 3. and 4. represent the most prudent source of information available to EA Networks for the purpose of estimating future costs.
A vast range of alternative algorithms can be proposed and defended but there is no authoritative judgement upon which is the most accurate and reliable.
EA Networks do not have sufficient internal expertise to promote any particular theory or speculate on how future costs will trend.
It is the opinion of EA Networks that the Treasury's CPI forecast is a reasonable indicator of future cost as it incorprates a range of factors that could influence the future cost of expenditure on the electricity network.
Even with additional cost escalation data, EA Networks current future cost modelling is not sufficiently granular to take full advantage of the additional detail.
The Treasury forecast extends to 2018. Beyond 2018, EA Networks have used the 2018 CPI value (2.2%) until 2023.

Commerce Act (Electricity Distribution Services Information Disclosure) Determination 2012

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1 of section 2.9

We, John Bruce Tavendale and Gary Richard Leech, being directors of Electricity Ashburton Limited trading as EA Networks certify that, having made all reasonable enquiry, to the best of our knowledge-

a) The following attached information of Electricity Ashburton Limited trading as EA Networks prepared for the purposes of clause 2.6.1 and subclauses 2.6.3(4) and 2.6.5(3) of the Electricity Distribution Information Disclosure Determination 2012 in all material respects complies with that determination.

b) The prospective financial or non-financial information included in the attached information has been measured on a basis consistent with regulatory requirements or recognised industry standards.

Tavendale
Director

Leech
Director

26 March 2014

EA networks

connecting our community