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EA NETWORKS ASSET MANAGEMENT PLAN UPDATE 2022-32

ASSET MANAGEMENT PLAN UPDATE FOR EA NETWORKS' ELECTRICITY NETWORK

Planning Period:	1 April 2022 to 31 March 2032
Disclosure Year:	2022-23
Disclosure Date:	31 March 2022
Approved by Board:	30 March 2022

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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.

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ASSET MANAGEMENT PLAN UPDATE

1 Scope of this Document

In certain 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 2022 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 2022 disclosure date.

This document is the EA Networks 2022-2032 electricity network Asset Management Plan Update. It presumes that the reader has examined the EA Networks 2021-31 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 2029-30 financial year. Without load growth in the Montalto area, the need for this development continues to be uncertain and it has been rescheduled for the 2030-2031 financial year. The associated projects provide:

- a 66 kV line to/from Mt Somers to Montalto 66kV zone substation (~$1.2M),
- a 66kV line to/from Carew to Montalto zone substation (~$3.5M), and
- 66 kV line bays in Mt Somers and Carew zone substations (~$450k).

These related projects have all been delayed by a further year. These load-driven projects are looking less and less likely to proceed.

Rural load growth remains largely static. The possibility of gravity pressurised piped irrigation development, which could not only postpone additional load but remove existing load, have made the situation quite uncertain. Nutrient discharge restrictions by ECAN have effectively suppressed new irrigation development in this area and other areas.

The 11 kV distribution network in the Montalto area is under pressure from existing load and, if Montalto 33 kV substation is unavailable for some reason, back-feeding into the area causes unacceptably low voltages. It is intended to convert the 11 kV distribution system to 22 kV in the Montalto area. This will allow the Montalto 33 kV substation to be removed, all load to be supplied from Mt Somers substation, and multiple 22 kV back-feed options to be available.

The proposed 66kV line between Hackthorne and Lauriston (~$3.7M) is driven by a combination of load growth in the Methven area and additional security to Lauriston, Methven, Hackthorne and Mt Somers during 66 kV line outages. Summer load has not increased in the Methven area but could still do so. It has been decided to delay the construction of the Hackthorne-Lauriston 66 kV line and associated works to coincide with a second GXP (2030). This new line would provide a ring of 66 kV from the new GXP. The immediate security concern about Lauriston and Overdale Zone Substations has been resolved with a short (3km) new 66 kV circuit from Lauriston Zone Substation to the Overdale-Methven 66 kV line (a location now referred to as "Lauriston T"). This 66 kV line has been delayed by Line Road's realignment uncertainty (Ashburton District Council – delayed by several years) but is largely finished and will now be completed in 2022-23. The associated 66 kV line bay at Lauriston has already been completed.

Decarbonisation efforts largely impact coal users within Mid-Canterbury. These include food processing, schools, and the hospital. All of these sectors are actively looking at or progressing the elimination of coal. At this stage, supplying the proposed additional decarbonisation loads appears to be possible.

Large solar farm developers have approached EA Networks with the notion of investigating connecting solar photovoltaic generation in the order of tens of MW. The summer irrigation load profile provides a reasonably synergistic relationship with this type of generation. The distance from the Transpower grid exit point and the 66 kV circuit thermal rating will dictate the ability of the 66 kV network to accommodate a large-scale solar farm.

Zone Substations

As mentioned above, the Montalto 66 kV zone substation (~$2M) has been rescheduled later than previously disclosed (now 2030-31). It is entirely possible that further delays may occur if sufficient irrigation or other load/generation does not eventuate.

It is intended to decommission the existing Montalto 33/11 kV Zone Substation as well as converting the Montalto Hydro Power Station to 22kV (from 33 kV) in 2025. The surrounding 11kV distribution network will be progressively converted to 22 kV. This will ultimately lead to the Montalto 33/11 kV substation becoming redundant. Should the load increase sufficiently, it will trigger development of the Montalto 66/22 kV Zone Substation on a new site (already secured).

The Fairton 33/11 kV Zone Substation has been dismantled, with only the building (privately owned) and some minor non-operational switchgear remaining. Talleys have purchased the ex-Silver Fern Farms Fairton site and intend to develop it over the coming years. This load will be served from the adjacent Fairton 66/22/11 kV Zone Substation.

With the prospect of demand control no longer being incentivised by Transpower's pricing, funds have been allocated for investment in an alternative load-control signalling technology that could offer much more granular control and near-real-time power system data gathering capabilities. Research and trials into viable alternatives to ripple technology are underway. Should the alternatives not prove to be viable, the new 66 kV ripple plant could be reinstated using the same funds. The existing 33 kV ripple plant at Elgin has been scheduled for replacement in 2026. This plant would be a hot standby for the new 66 kV plant, should that be installed. If an alternative signalling technology is introduced, the 33 kV ripple plant replacement funds may be allocated to expand that alternative system.

Distribution Network

The delay in Montalto zone substation (see above) causes downstream delays in a distribution project - the additional overhead and underground 22 kV network needed to integrate the Montalto 66 kV zone substation into the distribution network (~$760k). This project has been postponed, coinciding with Montalto zone substation construction. The conversion of the Montalto Hydro station to 22 kV (from 33 kV) will still proceed as planned (~$270k), as the 33 kV circuit connecting it will be converted to 22 kV.

The urban underground conversion programme is documented (project by project) by ranking pole condition assessments to determine appropriate project timing. The plan now contains projects that should remove every urban distribution (22 kV, 11 kV, or LV) power pole before 2029. The average annual cost of this programme is about $2M and is scheduled to end by 2030.

The urban underground conversion programme has been ambitious. Each year a reducing amount of the work has spilled over to the following year. There is a need to carefully manage the aged urban overhead line assets that the underground conversion programme replaces. Each conversion project (and the poles within it) will be carefully assessed and monitored to determine a strict priority to minimise the risk of failure. Where that risk is seen to be too high, mitigation measures will be introduced to reduce risk to an acceptable level.

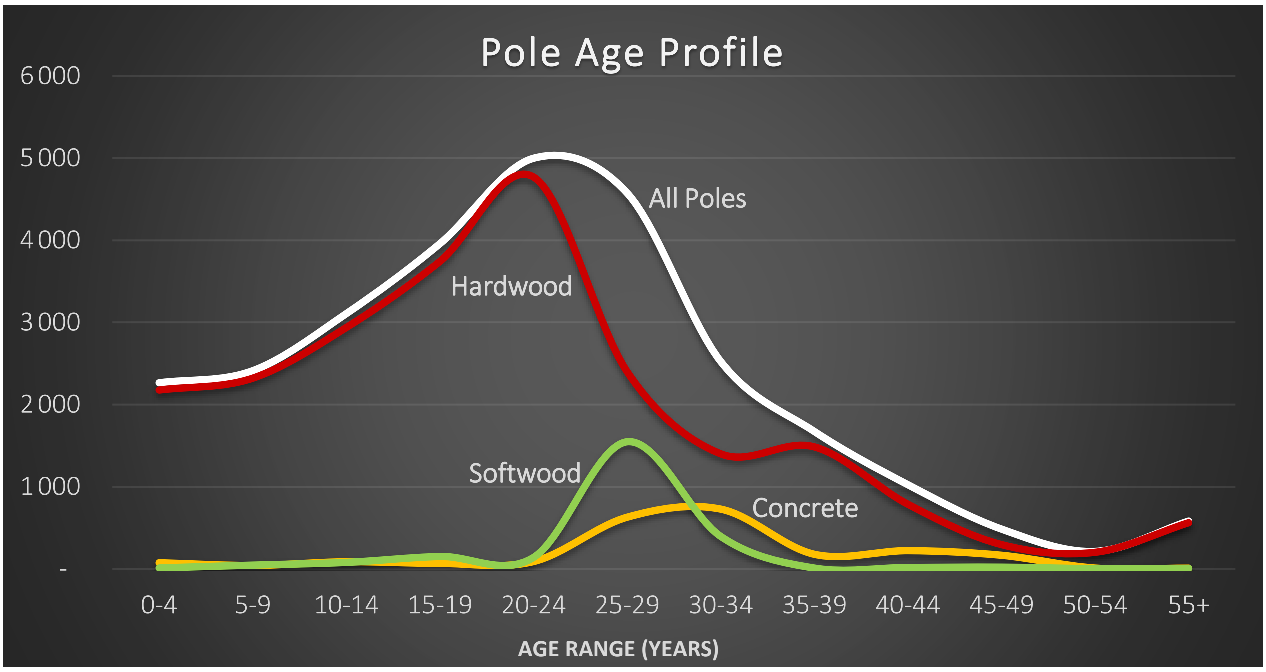
It is anticipated that urban residential growth will continue to rise. This will be both in the number of new subdivisions and the likelihood of EV (electric vehicle) charging becoming more common. Provided EV charging is off-peak, it is not anticipated to cause any noteworthy issues during the planning period.

The rural 11 kV to 22 kV conversion programme is fully documented. By 2028, very little rural 11 kV network should remain. The order of conversion may change as the priority for capacity and/or security is reassessed. There is no provision for the 22 kV conversion programme in 2029. The average annual cost of this programme is ~$350k in lines and ~$1M in distribution transformers and is scheduled to end by 2029.

The overhead distribution line rebuilding programme has two/three years of specific projects documented based upon pole condition inspections. Data has been captured for additional years but has yet to be fully assessed for inclusion as specific projects. This will occur in future plans. The effect of this is to reduce the large unscheduled Replacement and Renewal programme for the first two/three years. The average annual cost of this programme is about $2.5M and is ongoing.

Beyond the scheduled overhead rebuild projects, the allowance for rebuilding is fixed until 2026. It is then increased by 10% per annum for three years, as the impact of the aging pole population impacts condition-based rebuilding. Additional inspection, analysis, and assessment will take place to refine this forecast. The diagram below illustrates the issue (note that the poles over 50 years old are predominantly urban poles awaiting removal once underground conversion takes place).

Untreated hardwood pole lines can be expected to last between 40 and 50 years. Some of the "second growth" hardwood poles supplied during the 1980s are showing signs of premature decay. Not all poles are affected, and future pole inspections will reveal if the issue will cause a shift in rebuild cost timing. The use of concrete and treated softwood poles during the 1980s and 1990s will dampen the rebuild requirements as they have a longer life than the untreated hardwood poles. During the late 1990s and beyond, the hardwood poles used were treated with preservative compounds that should increase their useful life beyond 40-50 years.



The chart above shows that approximately 2 300 poles are currently being installed every 5 years (460 poles per annum). If the average pole life is 45 years and there are 28 000 poles, then the long-run average pole replacement rate needs to be about 3 100 poles every five years (620 poles per annum). In about 15-20 years, an increased need for pole replacements will begin to occur, and that might peak at 50-60% more than current rates. This can be managed with careful consideration of pole types, risk, and individual pole condition, but adequate construction resourcing will also be important.

The Ashburton township core 11 kV network programme is documented to provide a sequence of specific projects. The core 11 kV network programme aims to significantly increase capacity and reduce the count of consumers per urban 11 kV feeder. Delays in switchgear approval and site procurement have caused programme postponement by one year. The first two network centres are now largely complete and further duct, cable, and site development is progressing. This programme has an average annual cost of $650k and is scheduled to end by 2032.

Other Project and Programmes

Modern protection relays are based upon microprocessors and microelectronics. These devices have expected reliable lives of less than 30 years. Most relay manufacturers have said that 20-year-old devices are approaching the onset of unreliability and the limit of supportability with software. A programme of progressive 20-year-old relay replacement is in place to ensure in-service relay failures are a rare event. This programme has an average annual cost of about $70k.

The New/Smart Technology programme incorporates projects that are associated with either solar PV, grid-connected batteries, electric vehicle charging, or general contingencies for unknown assets. The total expenditure is similar to the discrete projects. The programme starts in 2026 and is shown until the end of the planning period. The average annual cost is ~$2M. A future plan will create specific projects to identify the work.

The Distribution Automation programme formalises a myriad of small projects. This retrospective automation programme runs from 2023 to 2025. By 2025 it is anticipated that most devices that can be remote controlled, will be. When appropriate, new equipment will be automated as part of the project creating the asset. The average annual cost of this programme is about $300k.

The recently commissioned ADMS (Advanced Distribution Management System), of which SCADA is only one aspect, will be progressively enhanced over time to provide additional features. The ADMS has the potential to improve both reliability and customer responsiveness.

Corporate IT systems continue to develop, and an allowance has been made for ongoing improvements and integration.

3 Changes to Lifecycle Asset Management Plans

The work order management / asset management system provides some facilities surrounding asset lifecycles. The inspection and testing of certain assets have been scheduled in the system. As the system matures and becomes better populated, the routine aspects of maintenance work will become more process driven.

There have been no material changes to the methodologies applied to lifecycle management plans during the last year. The previously manual process has now become more automated in some cases.

The identification of specific projects to replace end of life overhead lines (with either rebuilt overhead lines or underground cables) provides a clearer picture of future expenditure and resource requirements. This assessment work will continue to expand and gather condition data over time.

An external review of the risk and asset management processes in place at EA Networks is underway. Once this review has been completed, the beneficial action points will be adopted for implementation. The AMP will also be externally formally reviewed for completeness and to identify specific areas for improvement after considering any proposed changes to current asset management processes.

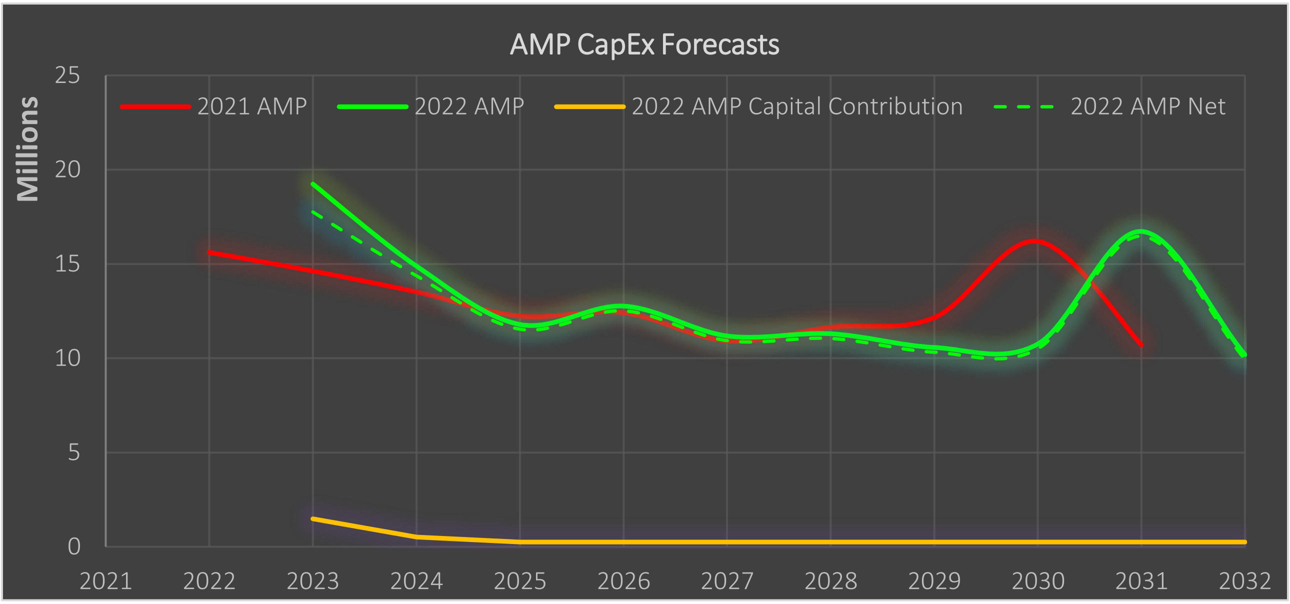
4 Reasons for Material Changes to Disclosure Schedules 11a and 11b

There are only minor timing changes to the disclosure schedules which are generally caused by delays in projects as a consequence of COVID-19 or other external factors.

Forecast Capital Expenditure – Schedule 11a

With the exception of 2023 and 2024, the forecast overall capital expenditure is similar to the previous disclosure for the same year. Towards the end of the planning period, project timing has changed.

The graph below shows that the expenditure predicted in the 2022-32 plan is close to the 2021-31 plan for the 2024-32 period. The key difference is at the beginning of the planning period (2023-24). This difference is caused by several larger projects being incomplete in 2021-22, many new residential subdivisions (partly offset by capital contributions), and some unscheduled IT development. At the end of the planning period, a group of projects that are less certain are essentially pinned to the end of the planning horizon and have been delayed by a year.



Note that the costs are shown in 2022-23 dollars, exclude CPI adjustment, and include capitalised labour. The disclosure schedules at the end of the document include inflation adjusted cashflows.

The 2021-22 year is likely to have some carry-over into the 2022-23 year. This could be up to $4M. The reasons for this include:

- Flooding event causing widespread farm and road damage which caused reprioritisation of civil contractors used for underground conversion work.
- COVID-19 interruptions decreasing efficiency and productivity.
- An unexpected resource issue caused a 33% reduction in underground conversion design throughput in the latter half of the year. This has now been addressed with the engagement of an external design resource (ongoing).
- The Ashburton 11 kV Core Network programme was partly delayed because of switchgear approval delays and site selection difficulties.
- State highway underground conversion was delayed due to uncertainty of the Waka Kotahi contribution timing.

A decision has been made to delay the rest of the Ashburton 11 kV Core Network programme by one year. This has lessened the impact of carry-overs on the 2022-23 year expenditure.

The unscheduled overhead line rebuild cost pool has been increased from the middle of the planning period to accommodate the pole age profile and anticipated gradual increase in overhead line rebuild rate.

The 10-year planning periods covered by the 2021-31 and 2022-32 plans have capital expenditure forecasts in them. A comparison of the forecasts shows the following:

Years	2021-31 Plan	2022-32 Plan
2022-32 (10y)	130.0M	129.4M
2023-31 (9y)	114.4M	119.2M

The overall (10y) comparison shows that, as predicted, the cumulative forecast is decreasing and will continue to do so (the net expenditure shows a larger downward trend).

The overlapping period (9y) has a variation between the two plans of about +$4.8M out of a total of about

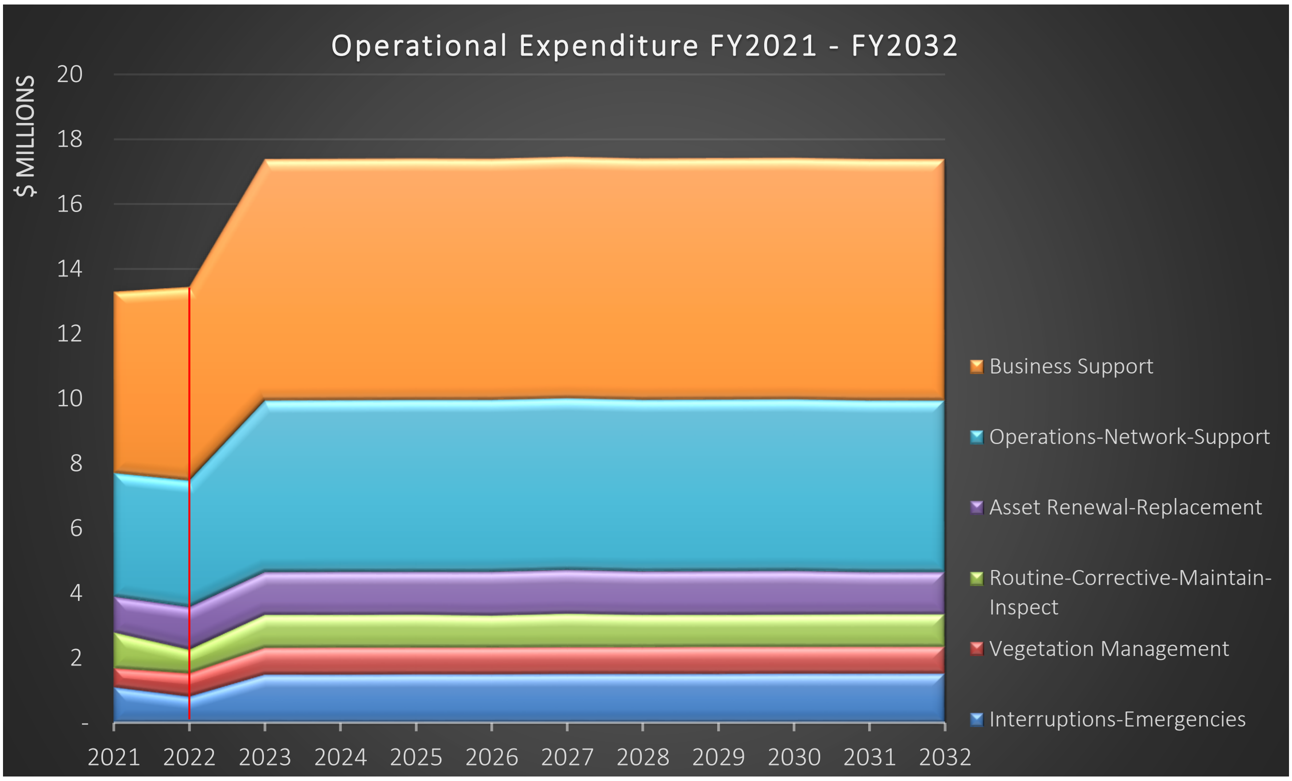
$129M. This represents approximately +3.7%. There are several reasons for this variation:

- Some project costs have been reassessed and this has caused a small increase in costs.
- Some project work from 2021-22 is incomplete or has been delayed. A portion of this expenditure work has been allowed for in the 2022-23 year.
- New non-network software expenditure has been identified.
- Significant quantities of residential subdivision proposals have been newly revealed for 2022-23.

There is the prospect of one or more large solar farm connections to EA Networks' system that have not been included in the schedule. The prospects are still not definite, and consequently no allowance has been made. Should one or more of the prospects become a commitment, it is likely to progress very quickly and cause increased expenditure, which would be offset by a 100% capital contribution.

Forecast Operational Expenditure – Schedule 11b

The overall operational expenditure forecast is significantly higher than the previous (2021 AMP) forecast. The future forecasts show a step rise in both categories of non-network expenditure. There are smaller rises in network expenditure.



Note that the costs are shown in 2022-23 dollars and exclude CPI adjustment. The disclosure schedules at the end of the document include inflation adjusted cashflows.

Business Support

Several key drivers have increased the forecast Business Support cost from the historical predictions:

(a) Additional staff being employed to accommodate:

- the base workload,
- HR support,
- additional processes and systems which require support,
- changing the pool of skills available for implementing and maintaining new technologies.

(b) Wage/salary inflation accompanying CPI.

(c) Software licensing and security costs continue to increase significantly, above those anticipated in previous plans, exacerbated by the need for remote working.

(d) Business assurance and R&D projects are proposed to explore better network and non-network performance.

(e) Various unscheduled COVID-19 costs that are potentially ongoing.

System Operations and Network Support

Similar drivers to Business Support have caused increases in forecast System Operations and Network Support:

1. Additional staff costs will also be incurred for similar reasons to those identified for Business Support.
2. Software licensing costs have increased well above those anticipated in previous plans.

Other Categories

The direct asset categories have increased caused by labour costs reflecting the CPI, as well as proposed changes in tree management processes.

The AMP forecast has been prepared using ABAA accounting standards.

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 work order management / asset management system is now in place. This system is maturing but will take some time to change the methodologies used to manage the electricity assets. A future AMP will detail any material changes that are planned or occur.

The external review of risk and asset management processes currently underway may result in changes to asset management practices, and this will be documented in the next full plan.

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 of 31 January 2022 and, where necessary, forecasted/ scaled to reflect the full 2021-22 disclosure year.

		Company Name	Electricity Ashburton Limited
		AMP Planning Period	1 April 2022 – 31 March 2032

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 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	3 587	3 964	2 939	2 785	2 830	2 937	2 991	3 090	3 145	3 069	3 310
11	System growth	1 122	1 970	4 549	4 159	5 825	4 539	4 259	3 118	5 370	10 704	2 862
12	Asset replacement and renewal	7 476	9 310	6 467	4 060	3 518	3 842	4 548	4 711	3 054	2 980	3 214
13	Asset relocations	302	-	-	-	-	-	-	-	-	-	-
14	Reliability, safety and environment:											
15	Quality of supply	663	1 457	722	622	1 034	286	313	436	419	2 806	2 414
16	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	299	389	178	188	156	162	166	171	174	170	183
18	**Total reliability, safety and environment**	962	1 845	900	810	1 190	449	479	607	593	2 976	2 597
19	**Expenditure on network assets**	13 449	17 089	14 854	11 814	13 363	11 767	12 277	11 526	12 162	19 728	11 983
20	Expenditure on non-network assets	721	2 150	845	906	896	919	939	996	981	999	1 025
21	**Expenditure on assets**	14 170	19 239	15 700	12 720	14 259	12 685	13 216	12 522	13 143	20 728	13 009
22												
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	809	1 482	541	271	278	285	291	298	304	311	318
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	13 361	17 757	15 158	12 449	13 981	12 401	12 925	12 224	12 839	20 417	12 691
28												
29	Assets commissioned	13 361	17 757	15 158	12 449	13 981	12 401	12 925	12 224	12 839	20 417	12 691
32		**$000 (in constant prices)**										
33	Consumer connection	3 587	3 964	2 796	2 571	2 543	2 577	2 568	2 596	2 585	2 469	2 605
34	System growth	1 122	1 970	4 328	3 838	5 234	3 984	3 657	2 620	4 415	8 610	2 253
35	Asset replacement and renewal	7 476	9 310	6 153	3 747	3 162	3 371	3 905	3 958	2 510	2 397	2 530
36	Asset relocations	302	-	-	-	-	-	-	-	-	-	-
37	Reliability, safety and environment:											
38	Quality of supply	663	1 457	687	574	929	251	269	366	344	2 257	1 900
39	Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	299	389	169	173	140	143	142	144	143	137	144
41	**Total reliability, safety and environment**	962	1 845	856	748	1 069	394	411	510	488	2 393	2 044
42	**Expenditure on network assets**	13 449	17 089	14 133	10 903	12 008	10 326	10 542	9 684	9 998	15 869	9 432
43	Expenditure on non-network assets	721	2 150	804	836	805	806	806	837	806	804	807
44	**Expenditure on assets**	14 170	19 239	14 938	11 739	12 814	11 132	11 348	10 520	10 804	16 673	10 239
45												
46	**Subcomponents of expenditure on assets (where known)**											
47	Energy efficiency and demand side management, reduction of energy losses	-	108	550	1 017	1 402	1 024	1 021	1 032	1 028	982	1 036
48	Overhead to underground conversion	1 698	3 709	3 264	1 755	1 191	1 197	1 551	1 438	-	-	-
49	Research and development	-	-	-	-	-	-	-	-	-	-	-

	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 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27	31 Mar 28	31 Mar 29	31 Mar 30	31 Mar 31	31 Mar 32
Difference between nominal and constant price forecasts	**$000**										
Consumer connection	-	-	143	215	287	360	423	494	560	600	705
System growth	-	-	221	321	591	556	602	498	955	2 094	609
Asset replacement and renewal	-	-	314	313	357	470	643	753	543	583	684
Asset relocations	-	-	-	-	-	-	-	-	-	-	-
Reliability, safety and environment:											
Quality of supply	-	-	35	48	105	35	44	70	75	549	514
Legislative and regulatory	-	-	-	-	-	-	-	-	-	-	-
Other reliability, safety and environment	-	-	9	14	16	20	23	27	31	33	39
Total reliability, safety and environment	-	-	44	63	121	55	68	97	106	582	553
Expenditure on network assets	-	-	721	911	1 355	1 441	1 735	1 842	2 164	3 859	2 552
Expenditure on non-network assets	-	-	41	70	91	112	133	159	175	195	218
Expenditure on assets	-	-	762	981	1 446	1 553	1 868	2 001	2 338	4 055	2 770

11a(ii): Consumer Connection

*Consumer types defined by EDB**	**$000 (in constant prices)**					
Urban LV	264	188	191	196	194	197
Urban Transformer	-	62	63	64	64	65
Urban Alteration for Safety (No new ICP created)	-	-	-	-	-	-
Urban Capacity Alteration (No new ICP created)	-	25	25	26	25	26
Rural LV	321	502	510	524	518	527
Rural Transformer	1 067	815	828	850	841	855
Rural Alteration for Safety (No new ICP created)	209	338	343	341	338	333
Rural Capacity Alteration (No new ICP created)	191	235	239	241	238	242
Other (including large subdivisions)	1 536	1 799	598	330	326	332
**include additional rows if needed*						
Consumer connection expenditure	3 587	3 964	2 796	2 571	2 543	2 577
less Capital contributions funding consumer connection	783	1 184	250	250	250	250
Consumer connection less capital contributions	2 804	2 780	2 546	2 321	2 293	2 327

11a(iii): System Growth

Subtransmission	49	85	-	-	12	-
Zone substations	428	90	-	-	1 514	369
Distribution and LV lines	127	15	796	164	162	165
Distribution and LV cables	227	429	1 041	307	1 068	942
Distribution substations and transformers	78	1 131	1 362	1 313	1 842	1 874
Distribution switchgear	104	5	28	20	321	327
Other network assets	109	216	1 101	2 034	314	307
System growth expenditure	1 122	1 970	4 328	3 838	5 234	3 984
less Capital contributions funding system growth	18	-	-	-	-	-
System growth less capital contributions	1 104	1 970	4 328	3 838	5 234	3 984

11a(iv): Asset Replacement and Renewal

	$000 (in constant prices)					
Subtransmission	136	1 161	469	-	-	-
Zone substations	12	170	68	70	69	70
Distribution and LV lines	1 844	3 317	1 650	1 075	1 063	1 175
Distribution and LV cables	1 700	3 360	2 926	1 667	1 111	1 154
Distribution substations and transformers	3 067	912	724	620	652	699
Distribution switchgear	624	375	304	316	267	273
Other network assets	93	16	13	-	-	-
Asset replacement and renewal expenditure	7 476	9 310	6 153	3 747	3 162	3 371
less Capital contributions funding asset replacement and renewal	8	298	265	-	-	-
Asset replacement and renewal less capital contributions	7 468	9 012	5 888	3 747	3 162	3 371

Row			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
106		for year ended	31 Mar 22	31 Mar 23	31 Mar 24	31 Mar 25	31 Mar 26	31 Mar 27

107 11a(v): Asset Relocations

Row		Project or programme*	$000 (in constant prices)					
109		SH1 - Walnut Ave Intersection Redesign	98	-	-	-	-	-
110		ADC Civic Centre & Library Distribution Substation	19	-	-	-	-	-
111		Ashburton CBD Duct Network	208	-	-	-	-	-
112		Rakaia Gorge - 11 kV Metering Point	(23)	-	-	-	-	-
113		N/A	-	-	-	-	-	-
114		*include additional rows if needed						
115		All other project or programmes - asset relocations	-	-	-	-	-	-
116		**Asset relocations expenditure**	302	-	-	-	-	-
117	less	Capital contributions funding asset relocations	-	-	-	-	-	-
118		**Asset relocations less capital contributions**	302	-	-	-	-	-
119								

122 11a(vi): Quality of Supply

Row		Project or programme*	$000 (in constant prices)					
124		SCADA - Distribution Automation Programme	-	294	299	307	-	-
		ZSS MTV - Reconfiguration	-	-	-	-	-	-
		ZSS Upgrading 110VDC Supply	55					
		Core Network Centres	302					
		22 kV Conversion - Methven Highway Springfield	60					
		Rural Ring Main Units	92					
		66kV OH Dampers Installation	-	55	-	-	-	-
125		11kV Core Network Centres	-	542	321	199	465	182
126		22kV Conversion - Mvn Hwy Sprgfld Rd to Mvn, AF to Nwtns Cnr	-	453	-	-	-	-
127		22kV OH Reconductor - Coldstream Rd	-	44	-	-	-	-
128		ZSS EGN - 33kV Ripple Plant Replacement	-	-	-	-	396	-
129		*include additional rows if needed						
130		All other projects or programmes - quality of supply	154	70	67	69	68	69
131		**Quality of supply expenditure**	663	1 457	687	574	929	251
132	less	Capital contributions funding quality of supply	-	-	-	-	-	-
133		**Quality of supply less capital contributions**	663	1 457	687	574	929	251
134								

137 11a(vii): Legislative and Regulatory

Row		Project or programme*	$000 (in constant prices)					
139		N/A	-	-	-	-	-	-
140		N/A	-	-	-	-	-	-
141		N/A	-	-	-	-	-	-
142		N/A	-	-	-	-	-	-
143		N/A	-	-	-	-	-	-
144		*include additional rows if needed						
145		All other projects or programmes - legislative and regulatory	-	-	-	-	-	-
146		**Legislative and regulatory expenditure**	-	-	-	-	-	-
147	less	Capital contributions funding legislative and regulatory	-	-	-	-	-	-
148		**Legislative and regulatory less capital contributions**	-	-	-	-	-	-
149								

151 11a(viii): Other Reliability, Safety and Environment

Row		Project or programme*	$000 (in constant prices)					
153		Distribution Earthing Upgrades	289	80	81	83	82	84
154		ZSS Security and Surveillance Programme	-	23	31	32	-	-
155		Satellite Comms, NOC/Transpower	-	18	-	-	-	-
156		Install Transformer Pad in Mt Hutt Zone Substation	-	212	-	-	-	-
157		N/A	-	-	-	-	-	-
158		*include additional rows if needed						
159		All other projects or programmes - other reliability, safety and environment	10	56	57	59	58	59
160		**Other reliability, safety and environment expenditure**	299	389	169	173	140	143
161	less	Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
162		**Other reliability, safety and environment less capital contributions**	299	389	169	173	140	143
163								

		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
164		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
165	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**

166 11a(ix): Non-Network Assets

167	**Routine expenditure**						
168	*Project or programme**	**$000 (in constant prices)**					
169	Routine Vehicles	-	440	320	320	320	320
170	Routine Plant	57	90	10	10	10	10
171	Routine Information Technology	262	370	370	370	370	370
	Routine Building Work	-	100	50	50	50	50
172	Software - GIS Development Programme	-	54	54	56	55	56
173	Aerial Photography	-	-	-	30	-	-
174	**include additional rows if needed*						
175	All other projects or programmes - routine expenditure	56	-	-	-	-	-
176	**Routine expenditure**	375	1 054	804	836	805	806
177	**Atypical expenditure**						
178	*Project or programme**						
179	Buildings - Office Furniture and Fittings	-	39	-	-	-	-
	Software	344					
	Customer Text Communication	-	70	-	-	-	-
	SF6 Analyser	-	43	-	-	-	-
	Software - Digitise Work Flows	-	350	-	-	-	-
180	Software - Integration Appplication Development	-	180	-	-	-	-
181	Software - Migration to Cloud	-	75	-	-	-	-
182	Software - TechOne Development	-	50	-	-	-	-
183	Solar PV for Corporate Buildings	-	225	-	-	-	-
184	**include additional rows if needed*						
185	All other projects or programmes - atypical expenditure	2	64	-	-	-	-
186	**Atypical expenditure**	346	1 096	-	-	-	-
187							
188	**Expenditure on non-network assets**	721	2 150	804	836	805	806

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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												
7		*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 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**	**31 Mar 28**	**31 Mar 29**	**31 Mar 30**	**31 Mar 31**	**31 Mar 32**
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	1 047	1 485	1 564	1 617	1 665	1 709	1 751	1 794	1 838	1 883	1 924
11	Vegetation management	539	831	873	901	925	947	968	990	1 011	1 034	1 057
12	Routine and corrective maintenance and inspection	850	1 015	1 061	1 097	1 099	1 180	1 156	1 184	1 213	1 243	1 270
13	Asset replacement and renewal	1 872	1 325	1 396	1 443	1 503	1 543	1 562	1 600	1 640	1 622	1 658
14	**Network Opex**	4 308	4 656	4 895	5 057	5 192	5 379	5 437	5 568	5 702	5 781	5 908
15	System operations and network support	4 817	5 290	5 565	5 738	5 892	6 034	6 167	6 302	6 441	6 583	6 727
16	Business support	5 894	7 429	7 808	8 050	8 267	8 466	8 652	8 842	9 037	9 236	9 439
17	**Non-network opex**	10 711	12 719	13 373	13 787	14 160	14 500	14 819	15 145	15 478	15 818	16 166
18	**Operational expenditure**	15 019	17 375	18 268	18 844	19 352	19 879	20 255	20 712	21 179	21 599	22 075
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	1 047	1 485	1 488	1 492	1 496	1 499	1 503	1 507	1 511	1 515	1 515
23	Vegetation management	539	831	831	831	831	831	831	831	832	832	832
24	Routine and corrective maintenance and inspection	850	1 015	1 010	1 012	988	1 035	992	995	997	999	999
25	Asset replacement and renewal	1 872	1 325	1 328	1 331	1 351	1 354	1 341	1 345	1 348	1 305	1 305
26	**Network Opex**	4 308	4 656	4 657	4 667	4 666	4 721	4 668	4 678	4 687	4 650	4 650
27	System operations and network support	4 817	5 290	5 295	5 295	5 295	5 295	5 295	5 295	5 295	5 295	5 295
28	Business support	5 894	7 429	7 429	7 429	7 429	7 429	7 429	7 429	7 429	7 429	7 429
29	**Non-network opex**	10 711	12 719	12 724	12 724	12 724	12 724	12 724	12 724	12 724	12 724	12 724
30	**Operational expenditure**	15 019	17 375	17 381	17 391	17 390	17 445	17 392	17 402	17 411	17 374	17 374
31	**Subcomponents of operational expenditure (where known)**											
32	Energy efficiency and demand side management, reduction of											
33	energy losses	-	-	-	-	-	-	-	-	-	-	-
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	1	220	220	220	220	220	220	220	220	220	220
36	Insurance	330	341	341	341	341	341	341	341	341	341	341
37	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
41	**Difference between nominal and real forecasts**	**$000**										
42	Service interruptions and emergencies	-	-	76	125	169	209	247	287	327	368	410
43	Vegetation management	-	-	42	69	94	116	137	158	180	202	225
44	Routine and corrective maintenance and inspection	-	-	51	85	111	144	163	189	216	243	270
45	Asset replacement and renewal	-	-	68	111	152	189	221	256	292	317	353
46	**Network Opex**	-	-	238	390	526	659	768	890	1 014	1 131	1 258
47	System operations and network support	-	-	270	443	597	739	872	1 007	1 146	1 288	1 432
48	Business support	-	-	379	621	838	1 037	1 223	1 413	1 608	1 807	2 010
49	**Non-network opex**	-	-	649	1 063	1 436	1 776	2 095	2 421	2 754	3 094	3 442
50	**Operational expenditure**	-	-	886	1 454	1 962	2 434	2 863	3 310	3 768	4 225	4 700

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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												
7					**Asset condition at start of planning period (percentage of units by grade)**							
8–9	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
10	All	Overhead Line	Concrete poles / steel structure	No.	-	0.34%	0.43%	69.13%	30.09%	-	2	0.34%
11	All	Overhead Line	Wood poles	No.	1.38%	1.79%	13.01%	39.77%	44.05%	-	2	3.17%
12	All	Overhead Line	Other pole types	No.	-	-	-	75.00%	25.00%	-	2	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	0.24%	2.65%	59.06%	38.06%	-	3	-
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km	-	-	-	-	-	-	N/A	-
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	-	16.87%	83.13%	-	3	-
16	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Oil pressurised)	km	-	-	-	-	-	-	N/A	-
17	HV	Subtransmission Cable	Subtransmission UG up to 66kV (Gas pressurised)	km	-	-	-	-	-	-	N/A	-
18	HV	Subtransmission Cable	Subtransmission UG up to 66kV (PILC)	km	-	-	-	-	-	-	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.	-	4.55%	22.73%	22.73%	50.00%	-	2	-
25	HV	Zone substation Buildings	Zone substations 110kV+	No.	-	-	-	-	-	-	N/A	-
26	HV	Zone substation switchgear	22/33kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
27	HV	Zone substation switchgear	22/33kV CB (Outdoor)	No.	-	-	87.50%	12.50%	-	-	3	-
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.	-	-	-	-	-	-	N/A	-
29	HV	Zone substation switchgear	33kV Switch (Pole Mounted)	No.	-	2.04%	29.93%	47.62%	20.41%	-	3	2.04%
30	HV	Zone substation switchgear	33kV RMU	No.	-	-	-	-	-	-	N/A	-
31	HV	Zone substation switchgear	50/66/110kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
32	HV	Zone substation switchgear	50/66/110kV CB (Outdoor)	No.	-	-	30.56%	37.50%	31.94%	-	3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	-	5.20%	33.53%	61.27%	-	2	-
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.	-	-	-	-	-	-	N/A	-
35												

36					**Asset condition at start of planning period (percentage of units by grade)**							
37–38	**Voltage**	**Asset category**	**Asset class**	**Units**	**H1**	**H2**	**H3**	**H4**	**H5**	**Grade unknown**	**Data accuracy (1–4)**	**% of asset forecast to be replaced in next 5 years**
39	HV	Zone Substation Transformer	Zone Substation Transformers	No.	-	8.57%	11.43%	31.43%	48.57%	-	3	8.57%
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.31%	3.03%	16.09%	43.86%	35.70%	-	3	4.34%
41	HV	Distribution Line	Distribution OH Aerial Cable Conductor	km	-	-	-	-	-	-	N/A	-
42	HV	Distribution Line	SWER conductor	km	-	-	-	-	-	-	N/A	-
43	HV	Distribution Cable	Distribution UG XLPE or PVC	km	0.01%	0.01%	0.64%	26.06%	73.29%	-	3	0.01%
44	HV	Distribution Cable	Distribution UG PILC	km	-	4.12%	81.04%	14.84%	-	-	1	2.06%
45	HV	Distribution Cable	Distribution Submarine Cable	km	-	-	-	-	-	-	N/A	-
46	HV	Distribution switchgear	3.3/6.6/11/22kV CB (pole mounted) - reclosers and sectionalisers	No.	-	-	30.30%	51.52%	18.18%	-	2	15.00%
47	HV	Distribution switchgear	3.3/6.6/11/22kV CB (Indoor)	No.	-	-	-	-	-	-	N/A	-
48	HV	Distribution switchgear	3.3/6.6/11/22kV Switches and fuses (pole mounted)	No.	0.01%	0.58%	4.24%	36.45%	58.72%	-	2	0.59%
49	HV	Distribution switchgear	3.3/6.6/11/22kV Switch (ground mounted) - except RMU	No.	-	-	-	-	-	-	N/A	-
50	HV	Distribution switchgear	3.3/6.6/11/22kV RMU	No.	4.69%	9.18%	13.28%	30.66%	42.19%	-	3	1.00%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.32%	6.77%	21.94%	27.57%	43.40%	-	3	2.00%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.21%	5.07%	16.81%	19.92%	57.99%	-	3	1.00%
53	HV	Distribution Transformer	Voltage regulators	No.	-	-	100.00%	-	-	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	2.55%	4.74%	11.31%	26.64%	54.74%	-	2	3.00%
55	LV	LV Line	LV OH Conductor	km	7.93%	11.45%	12.99%	56.73%	10.90%	-	3	19.38%
56	LV	LV Cable	LV UG Cable	km	0.02%	1.34%	6.53%	36.05%	56.07%	-	3	1.36%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.82%	2.46%	7.45%	39.35%	49.91%	-	2	3.28%
58	LV	Connections	OH/UG consumer service connections	No.	-	-	33.33%	33.33%	33.34%	-	3	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	0.42%	2.94%	1.26%	95.38%	-	2	3.00%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	10.00%	90.00%	-	3	25.00%
61	All	Capacitor Banks	Capacitors including controls	No.	-	-	-	-	-	-	N/A	-
62	All	Load Control	Centralised plant	Lot	-	66.67%	33.33%	-	-	-	3	66.67%
63	All	Load Control	Relays	No.	-	-	-	-	-	100.00%	1	-
64	All	Civils	Cable Tunnels	km	-	-	-	-	-	-	N/A	-

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2022 – 31 March 2032**

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
9	Ashburton 66/11kV [ASH]	19	22	N-1	20	86%	22	91%	Transformer	Two 20MVA 66/11kV transformers, steady state load transfer to/from NTN, and additional fast transfer switched capacity ensure acceptable security.
10	Carew 66/22kV [CRW]	15	17	N-1	9	88%	20	75%	No constraint within +5 years	Second transformer is one of two system spares and provides 100% firm capacity. Transfer capacity at 22kV is good.
11	Coldstream 66/22kV [CSM]	13	-	N	9	-	-	-	Transformer	Second Carew transformer provides an increase in transfer capacity. EFN 22kV conversion improved transfer capacity.
12	Dorie 66/22kV [DOR]	11	-	N	9	-	-	-	Transformer	Pendarves and Overdale substations offer close to 100% of firm capacity via transfer on 22kV distribution network.
13	Eiffelton 66/11kV [EFN]	9	-	N	4	-	-	-	Transformer	Transfer capacity has increased significantly with 22kV conversion. Now operating at 66/22kV, all load should be able to be back-fed.
14	Elgin 66/22kV [EGN] (Future)	-	-	-	-	-	-	-	Transformer	66/33/22kV transformer rated at 20MVA. Will partly unload some 66kV circuits and provide back-feeds at 22kV to other sites. Load secured by existing switched capacity.
15	Fairton 66/22/11kV [FTN]	8	22	N-1 Switched	11	36%	20	50%	No constraint within +5 years	New substation (2017) with 1x20MVA 66/22kV, 1x20MVA 66/11kV and 1x8MVA 22/11kV transformers. Station firm capacity is enhanced by adjacent switched transfer capacity at 22kV and 11kV.
16	Hackthorne 66/22kV [HTH]	15	-	N	9	-	-	-	Transformer	Second Carew transformer and 22kV distribution provides extra transfer capacity. 66kV MSM and future MON also significantly increase transfer capacity.
17	Highbank 66/11kV [HBK]	8	-	N	-	-	-	-	Subtransmission circuit	Owned by Trustpower. Winter: generation. Summer: pump load. By agreement, EA Networks provide N 66kV subtransmission security beyond Methven.
18	Lagmhor 66/22kV [LGM]	9	-	N	6	-	-	-	Transformer	22kV transfer capacity uses HTH, CRW, and TIN.
19	Lauriston 66/22kV [LSN]	15	-	N	7	-	-	-	Transformer	Transfer capacity uses 22kV from OVD, FTN, & MTV, larger OVD transformer, and increased MTV 22kV supply capability.
20	Methven 33/11kV [MVN]	-	-	N	4	-	-	-	No constraint within +5 years	Load transferred to Methven 66/11kV substation in 2016. Acting as hot standby for Methven 11kV load until 2023.
21	Methven 66/22/11kV [MTV]	5	8	N-1 Switched	5	63%	-	-	Transformer	22/11kV transformer provides significant back-feed from LSN. 66/22kV, 66/11kV & 22/11kV transformers will provide 100% transfer capacity in 2022.
22	Methven 66/33kV [MTV]	5	-	N	5	-	-	-	No constraint within +5 years	Most 33kV load beyond MTV will be converted to 66/22kV. Mt Hutt 33/11 kV load will be supplied by stepping up 22/33 kV (2022).
23	Mt Somers 66/22kV [MSM]	3	5	N-1 Switched	3	58%	-	-	Transformer	66/22kV operation plus conversion of surrounding distribution network to 22kV permits adequate switched transfer capacity. Additional 66kV circuit in 2022 will provide N-1 subtransmission security (currently N subtransmission security).
24	Mt Hutt 33/11kV [MHT]	2	-	N	2	-	-	-	Transformer	Considered adequate. 33kV and 11kV lines share common poles. Possible 22kV conversion to MTV would increase switched transfer capacity.
	Montalto 33/11kV [MON]	2	-	N	1		-	-	Transformer	Conversion to 22kV distribution network increases transfer capacity in 2024-25. Redundant as 22kV conversion proceeds.
	Northtown 66/11kV [NTN]	14	22	N-1	20		20	80%	No constraint within +5 years	Additional 11kV Core Network cables in Ashburton increase fast transfer capacity from ASH.
	Overdale 66/22kV [OVD]	14	-	N	10		-	-	Transformer	Significant transfer capacity from 66/22kV transformers at adjacent substations ([PDS], [FTN], [DOR], & [LSN]).
25	Pendarves 66/22kV [PDS]	16	22	N-1	28	73%	20	80%	No constraint within +5 years	Firm capacity limit is N-1 transformer capacity limit plus switched 22 kV backfeed. Second transformer is one of two system spares.
26	Seafield 22/11kV [SFD22]	-	-	N	5	-	-	-	Transformer	Decommissioned as 33/11kV and converted to 22/11kV for 5MVA limited transfer back-up supply to SFD66 (several minutes for restoration).
27	Seafield 66/11kV [SFD66]	8	5	N-1 Switched	5	160%	-	-	Transformer	Negotiated security with sole industrial customer. A second transformer and short length of 66kV line would provide 100% firm capacity. Remote-controlled change-over between full capacity 66/11kV and adjacent critical load only 22/11 kV substations (several minutes).
28	Wakanui 66/22kV [WNU]	13	-	N	10	-	-	-	Transformer	Elgin's 66/33kV transformer conversion to 66/22kV has increased 22kV fast transfer capacity significantly.

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

Company Name	Electricity Ashburton Limited
AMP Planning Period	1 April 2022 – 31 March 2032

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**							
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 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
11	*Consumer types defined by EDB**							
12	Urban LV		48	45	45	45	45	45
	Urban Transformer		7	5	5	5	5	5
	Urban Alteration for Safety (No new ICP created)		-	-	-	-	-	-
	Urban Capacity Alteration (No new ICP created)		2	5	5	5	5	5
	Rural LV		56	60	60	60	60	60
13	Rural Transformer		60	60	60	60	60	60
14	Rural Alteration for Safety (No new ICP created)		24	25	25	25	25	25
15	Rural Capacity Alteration (No new ICP created)		11	15	15	15	15	15
16	Other		58	60	40	20	20	20
17	**Connections total**		266	275	255	235	235	235
18	**include additional rows if needed*							
19	**Distributed generation**							
20	Number of connections		55	55	56	56	55	60
21	Capacity of distributed generation installed in year (MVA)		0	0	50	25	1	1
22	**12c(ii) System Demand**							
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 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
25	GXP demand		158	181	184	186	188	190
26	*plus* Distributed generation output at HV and above		2	2	2	2	2	2
27	**Maximum coincident system demand**		159	183	186	188	190	192
28	*less* Net transfers to (from) other EDBs at HV and above		(0)	(0)	(0)	(0)	(0)	(0)
29	**Demand on system for supply to consumers' connection points**		159	183	186	188	190	192
30	**Electricity volumes carried (GWh)**							
31	Electricity supplied from GXPs		454	508	514	519	524	529
32	*less* Electricity exports to GXPs		-	0	0	0	0	0
33	*plus* Electricity supplied from distributed generation		144	141	141	141	141	141
34	*less* Net electricity supplied to (from) other EDBs		(0)	(0)	(0)	(0)	(0)	(0)
35	**Electricity entering system for supply to ICPs**		598	649	654	660	665	670
36	*less* Total energy delivered to ICPs		563	607	612	617	622	627
37	**Losses**		35	42	42	43	43	43
38								
39	**Load factor**		43%	41%	40%	40%	40%	40%
40	**Loss ratio**		5.9%	6.5%	6.5%	6.5%	6.5%	6.5%

Company Name	**Electricity Ashburton Limited**
AMP Planning Period	**1 April 2022 – 31 March 2032**
Network / Sub-network Name	

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

		Current Year CY	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
8							
9	for year ended	**31 Mar 22**	**31 Mar 23**	**31 Mar 24**	**31 Mar 25**	**31 Mar 26**	**31 Mar 27**
10	**SAIDI**						
11	Class B (planned interruptions on the network)	118.0	120.0	120.0	120.0	120.0	120.0
12	Class C (unplanned interruptions on the network)	137.0	110.0	107.0	100.0	95.0	95.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.41	0.40	0.40	0.40	0.40	0.40
15	Class C (unplanned interruptions on the network)	1.75	1.25	1.25	1.25	1.25	1.25

Schedule 14a Mandatory Explanatory Notes on Forecast Information

1. This Schedule requires EDBs to provide explanatory notes to reports prepared in accordance with clause 2.6.6.

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

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

3. In the box below, comment on the difference between nominal and constant price capital expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11a.

The difference is 0.0% for the 2022-23 year. Costs have been prepared using 2022-23 values for labour, plant, and materials. Years after 2022-23 have been escalated by the "Half Year Economic and Fiscal Update 2021" CPI Forecast by the New Zealand Government Treasury published in December 2021. When the forecast ends, the final year CPI value has been used until the period end.

(https://www.treasury.govt.nz/publications/efu/half-year-economic-and-fiscal-update-2021)

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

4. In the box below, comment on the difference between nominal and constant price operational expenditure for the current disclosure year and 10 year planning period, as disclosed in Schedule 11b.

The difference is 0.0% for the 2022-23 year. Costs have been prepared using 2022-23 values for labour, plant, and materials. Years after 2022-23 have been escalated by the "Half Year Economic and Fiscal Update 2021" CPI Forecast by the New Zealand Government Treasury published in December 2021. When the forecast ends, the final year CPI value has been used until the period end.

(https://www.treasury.govt.nz/publications/efu/half-year-economic-and-fiscal-update-2021)

Financial Year (ending March)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Treasury CPI Forecast (%)	5.1	3.1	2.7	2.4	2.2	2.2	2.2	2.2	2.2	N/A
Cumulative CPI Price Inflator	1.0000	1.0510	1.0836	1.1128	1.1395	1.1646	1.1902	1.2164	1.2432	1.2705

Directors' Certification for Year-beginning Disclosures.

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, **Philip John McKendry** and **Paul Jason Munro**, being directors of **Electricity Ashburton Limited** certify that, having made all reasonable enquiry, to the best of our knowledge:

a) the following attached information of **Electricity Ashburton Limited** prepared for the purposes of clauses 2.6.3, 2.6.6 and 2.7.2 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.

c) The forecasts in Schedules 11a, 11b, 12a, 12b, 12c and 12d are based on objective and reasonable assumptions which both align with **Electricity Ashburton Limited's** corporate vision and strategy and are documented in retained records.

Philip John McKendry

Paul Jason Munro

31 March 2022.

connecting our community