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EA Networks Asset Management Plan <u>Update</u> 2024-34

Asset Management Plan Update for EA Networks' Electricity Network

Planning Period:	1 April 2024 to 31 March 2034
Disclosure Year:	2024-25
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EA Networks
Private Bag 802
Ashburton 7740

Website: http://www.eanetworks.co.nz
Telephone: (03) 3079800
Email: enquiries@eanetworks.co.nz

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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 General Manager - Network.

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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 2024 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 2024 disclosure date.

This document is the EA Networks 2024-2034 electricity network Asset Management Plan Update. It presumes that the reader has examined the EA Networks 2023-33 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 a second 220/66kV GXP would be developed connected to the Transpower Islington – Livingston circuit (Roxborough – Islington A single circuit line) in the vicinity of Mitcham. Included in AMP 2023 was the expenditure for associated 66kV circuits to connect the new GXP into the 66kV sub-transmission. By evaluating a number of factors, this AMP update has concluded that the second GXP is not required within the ten-year time frame of this plan, so the projects and expenditure have been excluded from the forecast. The factors considered included:

- The existing Transpower Ashburton 220/66kV GXP is very secure, with four circuits connected to a robust high-capacity double circuit transmission line and three 220/66kV supply transformers connected to the Elgin multi-zone, ring 66kV bus.
- Discussions with Transpower confirmed that the risk of tower failure on this 220kV double circuit line is very low, whether from earthquakes or river foundation washouts.
- The 220/66kV supply transformers provide a nominal 220 MVA of firm capacity, which increases to around 250 MVA when cyclical short-term contingency overload ratings are applied (as would be the case following the loss of one of the 120 MVA transformers).
- Transpower has a prudent 10-year load forecast of 254 MVA which significantly exceeds EA Networks' expectation for load growth over the period.

Taking these factors into account has led EA Networks to the conclusion that the second 220kV GXP is not required within the 10-year forecast period of this AMP.

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.

With the postponement of a second GXP, the need for the proposed 66kV line between Hackthorne and Lauriston (which would provide a closed ring of 66 kV from the new GXP) has been shifted beyond the plan horizon. 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 2024-25. The associated 66 kV line bay at Lauriston has already been completed.

The existing 66 kV line between Methven and Mt Somers (currently operating at 33 kV) will be converted to 66 kV within 2024. This will increase security to Mt Somers and Methven by connecting the southern 66 kV circuits to the northern 66 kV circuits.

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, the hospital and high school have largely completed works to fully or partially remove coal-fired heating. Supplying additional decarbonisation loads appears to be possible.

Multiple 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 large-scale solar farms. Two have committed to connection contracts (totalling 54 MW), and several more appear to be advancing their plans. It is anticipated that there will be 66 kV voltage constraints during periods of high generation and low load that will require management.

Zone Substations

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 2025-26. 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, but development is not forecast within the planning period).

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. Existing and new load is being/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 had 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 and data gathering are underway. Although technically viable, the default distributor agreement commits EA Networks to maintaining the ripple signal for retailers and meter equipment providers. The existing 33 kV ripple plant coupling cell at Elgin is currently being replaced with a 22 kV coupling cell on a different winding of the same transformer. This plant is operated synchronously in parallel with the existing 11 kV ripple pant at Ashburton zone substation providing n-1 levels of reliability.

The construction of Lauriston solar farm (50MVA) has resulted in a significant capacity increase at Lauriston substation. A second 66/22 kV transformer (35MVA), two new 22 kV switchboards, and a building extension are being installed. This work is being funded as an incremental cost by the solar developer. Lauriston substation is now a generation congested site, and all further applications to connect generation to Lauriston will be export restricted to prevent overloading the two Lauriston transformers during low load.

A solar farm (15 MW) at Mt Somers has been included in the plan. This will require some reconfiguration of Mt Somers substation and the swap of the existing 15 MVA 66/22 kV transformer with a larger 20 MVA unit. The solar developer is funding this work as an incremental cost. Mt Somers substation will also be approaching generation congested status, and there will be limited opportunity for further exporting generation connections (in time, generation will only be able to meet load behind the meter without funding additional network investment).

A 30MW solar farm south of Ashburton has been included as a representative project of several different solar proposals that may or may not come to fruition. This would require a new greenfield 66 kV connection to be established. This work would be fully funded as an incremental cost by the developer.

In future, a distributed energy resources management system (DERMS) could assist generation to match available capacity/load and dynamically provide some additional export capability where previously there was none allocated. This would provide a financial benefit to those generators. DERMS would primarily be installed to protect the distribution network from operating outside the desirable bounds of voltage and current because of generation. The connections causing the potential for these excursions (generation) would incur a share of charges to fund DERMS. DERMS funding has been allowed for in the plan.

Distribution Network

The conversion of the Montalto Hydro station to 22 kV (from 33 kV) will proceed as planned, as the 33 kV circuit connecting it will be converted to 22 kV by 2026.

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 2033. The average annual cost of this programme is about $2M and is scheduled to end by 2033.

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. Some overhead lines have been reassessed as suitable for remaining in service for up to five years longer than previously determined, extending the programme by three to four years beyond that documented in previous plans.

It is anticipated that urban residential load 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.

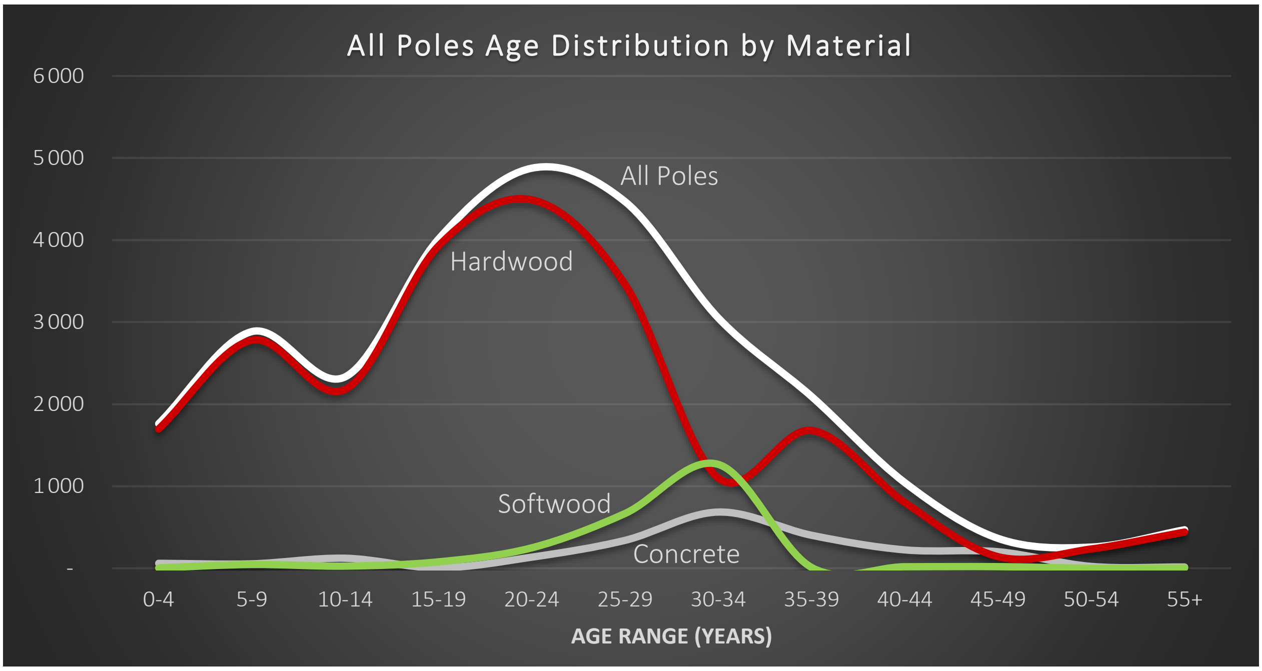
The rural 11 kV to 22 kV conversion programme is fully documented. By 2031, very little rural 11 kV network should remain. The order of conversion may change as the priority for capacity and/or security is reassessed. There is no provision for the 22 kV conversion programme in 2031. The average annual cost of this programme is ~$350k in lines and ~$1M in distribution transformers and is scheduled to end by 2031.

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 2030. It is then increased by about 6% per annum for the remaining years, as the impact of the aging pole population results in additional 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 below 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 10-15 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 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 2034 (two years later than previous plans).

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 Decarbonisation & Smart Technology programme incorporates projects that are associated with either solar PV, grid-connected batteries, electric vehicle charging, coal boiler removal, 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 ~$1.7M. In some years specific projects have been allocated. Future plans will create additional specific projects to identify the work as it becomes apparent it is necessary.

The Distribution Automation programme formalises a myriad of small projects. This retrospective automation programme runs from 2023 to 2030. By 2030 it is anticipated that most devices that should 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 $100k.

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 as well as improve network planning.

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 has been externally formally reviewed for completeness and this has identified 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

Significant points related to the changes to the capital and operating expenditure profile in the AMP 2024 update compared to AMP 2023 are:

- The 10-year capital expenditure is higher overall by $16.7m, 11.6%. Significant movements are related to the addition to Asset Replacement and Renewal of a large programme of shared on-property lines and safety driven replacement of on-property transformer poles.
- The 10-year operating expenditure is higher overall by $0.13m 0.1%. Significant movements are related to top-down review of historical spending in various network operational expenditure categories to reset expenditure down to a level expected in an average year. Vegetation management is an exception, recent historical vegetation management spend has lagged below budget due to delivery issues. Forecasted spend includes tendering of a vegetation management contractor to target both reactive in-zone trimming and proactive removal of vegetation posing a risk from outside of the growth limit zone.
- Two utility scale solar farms are committed, and two more potential large solar farm connections have been incorporated.
- Only one industrial connection expansion in two stages has been incorporated. Several other potential projects have been discussed along with the potential for decarbonisation, but these have not been incorporated, due to the inherent uncertainty and lack of firm commitment.
- Inclusion of renewal of shared on-property lines and transformer poles as an alignment with:
    a. the regulations related to defining network assets as sharing supply to multiple landowners, and
    b. as a safety and environment initiative related to the failure risk of field workers climbing transformer poles on-property when assets in those situations are currently poorly maintained and can become unsafe under private ownership.
- These programmes are additional to the DPP4 and AMP 10-year capital forecast and hence contributed significantly to the additional expenditure for Asset Replacement and Renewal and Other Reliability, Safety and Environment in this AMP 2024 forecast.
- Revision of project cost estimates for escalation in materials and labour rates due to inflationary pressure.
- Non-network operational expenditure shows additional investment in people, data, and systems to operate a future-fit, digital network in an increasingly complex environment to deliver the expected needs of efficient network operations and asset management, decarbonized process heat and transportation, as well as enabling connection of fluctuating renewable solar generation and

flexible demand.

To explain terminology, FY2025 is the financial year ended 31 Mar-25. The regulated five-year DDP4 period commences 1 April 2025 (FY2026) and concludes 31 Mar-30 (FY2030). The AMP 2024 10-year budget forecast period commences 1 April 2024 (FY2025) and concludes on 31 Mar-34 (FY2034).

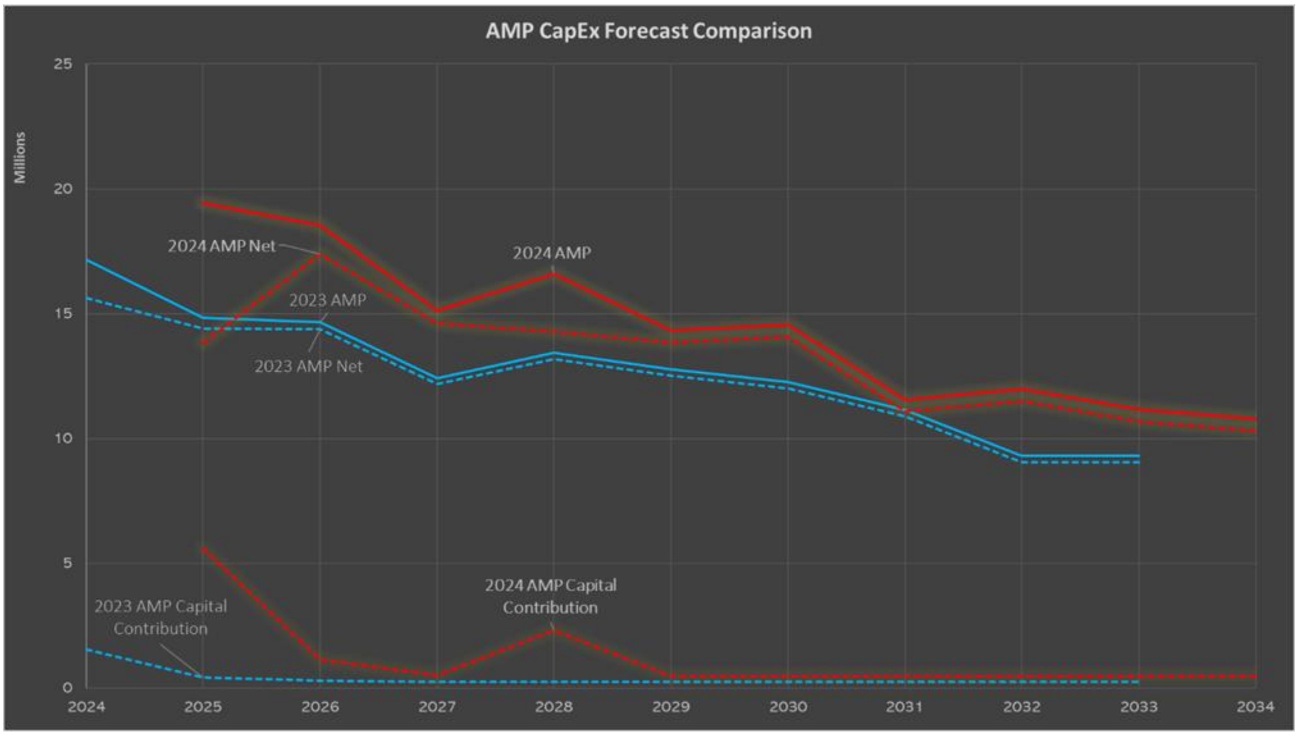
Forecast Capital Expenditure – Schedule 11a

AMP 2024 versus AMP 2023 10-year Capital Expenditure

The comparison of the 10-year capital expenditure between AMP 2024 and AMP 2023 shows:

- Increased capital spend in FY2025 largely due to specific customer connections (Lauriston Solar Farm and ANZCO) that nets out when capital contributions are accounted for.
- A generally higher capital spend across the period, accounted for by:
  - Inclusion of renewal of shared on-property lines and transformer poles as an alignment with regulation related to defining network assets as sharing supply to multiple landowners, and as a safety and environment initiative related to the failure risk of field workers climbing transformer poles on-property, when assets in those situations can be sub-optimally maintained and may become unsafe under private ownership.
  - Revision of project cost estimates for escalation in materials (international procurement and shipping inflation) and labour rates due to skilled labour shortages and wage increases.
- Expenditure matched with a capital contribution has been assumed related to the potential connection of a 15MW solar farm in 2026 and a 30MW solar farm in 2028.
- The declining expenditure trend is related to the current state of the network, having had a significant period of renewal and voltage conversion over the period circa 2000 to 2020. The network asset condition is higher on average than the majority of distribution networks in NZ. Despite the increased investment included in the 2024 10-year forecast, the declining trend is still evident as overhead renewal, overhead to underground conversions volumes are reduced.

The graph below shows that the expenditure predicted in the 2024-34 plan is higher than the 2023-33 plan for the entire period except for FY 2031. The key differences are noted above.



Note that the costs are shown in 2024-25 dollars, exclude CPI adjustment, and include capitalised labour. The disclosure schedules at the end of the document include inflation adjusted cashflows.

The 2023-24 year is likely to have some carry-over into the 2024-25 year. This could be up to $3M. The reasons for this include:

- The initial projects in the Ashburton 11 kV Core Network programme were delayed for a further year because of engineering resource limitations, switchgear approval delays and site selection difficulties.
- State highway underground conversion was delayed due to design difficulties in finding a viable corridor around existing underground services and design drawing resource shortages.
- The Elgin ripple plant replacement was delayed by a protracted tender round that required several iterations while options for reconfiguration were worked through.
- The 22 kV surge arrester replacement programme was delayed while data was gathered, and a suitable new earth tail configuration was developed and sourced.
- Some underground conversion projects have been slightly delayed by significant subdivision activity that now appear to be receding to more routine levels.

A decision has been made to defer and re-phase the rest of the Ashburton 11 kV Core Network programme as detailed further below.

The unscheduled overhead line rebuild cost pool has been shown to increase (~6% p.a.) from the middle of the planning period to accommodate the pole age profile and anticipated gradual increase in overhead line rebuild rate.

DPP4 5-year Comparison of Changes in Capital Expenditure

The following table is a comparison of the total capital expenditure within the DPP4 (Default Price Period 4) period. This is from a template provided by the Commerce Commission for the evaluation of the differences in expenditure between the two AMPs. It highlights expenditure increases of greater than 5% and expenditure outside of defined variance threshold bands.

Capital expenditure category	AMP2024 DPP4 $000	AMP2023 DPP4 $000	Difference $000	x % variance	5% threshold met?	Variance threshold test	Variance threshold met?	Requirement for additional supporting information met?
Consumer connection	19,550	17,894	1,655	9.3%	Yes	-8%>x>15%	No	No
System growth	22,215	23,775	(1,560)	-6.6%	Yes	-8%>x>15%	No	No
Asset replacement and renewal	24,823	17,584	7,239	41.2%	Yes	-3%>x>10%	Yes	Yes
Asset relocations	0	0	0	N/A	N/A	-8%>x>15%	N/A	No
Quality of supply	4,067	4,003	64	1.6%	Yes	-3%>x>10%	No	No
Legislative and regulatory	117	109	8	7.2%	No	-8%>x>15%	No	No
Other reliability, safety and environment	5,415	2,120	3,295	155.4%	Yes	-3%>x>10%	Yes	Yes
Non-network assets	3,098	2,305	793	34.4%	No	-8%>x>15%	Yes	No
Total	**79,284**	**67,790**	11,494	17.0%				

Table 1: Capital Expenditure Comparison AMP 2024 versus AMP 2023

DPP4 5-year Comparison of Changes in Operational Expenditure

The following table is a comparison of the total capital expenditure within the DDP4 period. This is from a template provided by the Commerce Commission for the evaluation of the differences in expenditure between the two AMPs. It highlights expenditure increases of greater than 5% and expenditure outside of defined variance threshold bands.

Operational expenditure category	AMP2024 DPP4 $000	AMP2023 DPP4 $000	Difference $000	x % variance	5% threshold met?	Variance threshold test	Variance threshold met?	Requirement for additional supporting information met?
Service interruptions and emergencies	4,307	7,516	(3,209)	-42.7%	No	-8%>x>15%	Yes	No
Vegetation management	5,223	4,157	1,066	25.6%	Yes	-8%>x>15%	Yes	Yes
Routine and corrective maintenance and inspection	7,854	5,114	2,740	53.6%	Yes	-8%>x>15%	Yes	Yes
Asset replacement and renewal	7,760	6,739	1,021	15.2%	Yes	-8%>x>15%	Yes	Yes
System operations and network support	32,543	35,630	(3,087)	-8.7%	Yes	-8%>x>15%	Yes	Yes
Business support	40,576	41,010	(434)	-1.1%	Yes	-8%>x>15%	No	No
Total	**98,263**	**100,166**	(1,903)	-1.9%				

Table 2: Operational Expenditure Comparison AMP 2024 versus AMP 2023

Cost Escalation Commentary:

Revision of projects, programmes, and activity cost estimates for escalation in materials and labour rates has been applied across the 10-year period of the AMP 2024 budget.

Overhead and Underground projects cost estimates have been revisited to confirm scope, design, and the magnitude of inputs that determine cost. Revised cost estimation tools have accounted for lessons learnt in recently completed projects about labour hours required for activities, cost escalation of materials, internal and external contractor rates, and incorporation of traffic management costs to meet higher standards of road safety and compliance. Materials costs have escalated due to international pressures on raw materials, demand, and shipping delays/shortages.

AMP 2024 10-year Capital Budget

This section highlights aspects of the 10-year capital budget under the regulatory expenditure categories.

Customer Connection

This includes estimated budget for connections, with allowance for capital contributions and connection fees as applicable. EA Networks supplies and owns network transformers, so this is budgeted separately.

Customer connections for residential, including at-scale urban subdivisions, and ad-hoc urban and rural new connections is budgeted at lower levels over the 10-year period than seen in 2022 and 2023, when significant subdivision development was occurring. We believe that this recent high level of subdivision activity has created a surplus and is not reflective of the future. In Mid-Canterbury we are seeing ample subdivided sections, but sales and further growth are being held back by the cost of building, inflationary pressures, and higher interest rates. Commercial connections are maintaining reasonable levels of activity.

Significant Connections – Solar Farms

The following assumed projects have been included in the capital forecast, with full capital contribution as per Part 6 of the Code governing distributed generation connections. For regulatory reasons both the capital spent, and capital contributions received are disclosed. From a delivery perspective, it is helpful to review the total capital spend disregarding contributions, to assess the level of expenditure and labour hours required for resource planning. Two uncommitted solar farm prospects have been included in the forecast, out of a larger pool of potential interested solar farms at different stages in the connection application process. This is to signal the resource and cashflow impacts of solar farm customer connections. The actual outcome of solar farm connections is highly uncertain, but there is significant interest and applications in hand.

- Lauriston Solar Farm: This has significant scope, including a new substation transformer, switchgear, 22kV cable feeders, protection, and controls.
- East of Tinwald Solar Farm: (project committed, 6.5 MW) $0.13m with a relatively simple 22kV feeder connection requiring an overhead line upgrade and interface distribution switchgear.
- Potential 15MW solar farm: (uncommitted, forecast for FY2026) $0.6m in the northwestern part of the network.
- Potential 30MW solar farm: (uncommitted, forecast for FY2028) $2.0m in the northwestern part of the network.

Significant Connections – Industrial

A committed industrial supply upgrade at ANZCO is forecast to cost $0.66m; for new switchgear, protection upgrade, and additional distribution transformer capacity within the meat processing plant. This upgrade will allow ANZCO to install more energy efficient chilling and reduce coal-fired boiler steam for absorption cooling. ANZCO have signalled an additional small step capacity increase, and this has been included at $0.15m in FY2027.

Forecasting the connection of new industrial loads is highly uncertain, as the connecting party needs to line up appropriately zoned land, resource consents, infrastructure costs (including electricity, water, wastewater, and access to transportation), and skilled people. The developing party are often maintaining a number of site options for economic comparison and commercial tension up until financial commitment, at which point an often urgent and time bound request for connection is made. Examples of potential connections are as follows:

- Talley's are a significant food processing customer and have requested design and cost estimates for additional food processing on their site. The required details for design have not yet been provided. This connection has not been included in the forecast for the reasons outlined above.
- Engagement with the developer of an industrial park in the northeastern part of the network is ongoing, with acceptance of a quote to connect circa 6 MW of load. Further expansion has been scoped via a high-level concept design. The subsequent expansion of this connection beyond 6 MW has not been included in the forecast for the reasons outlined above.
- An expression of interest has been received from a significant new industrial load that could connect in the Ashburton area in circa two years' time. Connection of the load is considered feasible albeit with only high-level concept design. This connection has not been included in the forecast for the reasons outlined above.

Decarbonisation of industrial load may require additional network investment within the 10-year period. Feedback from industrial customers indicates that they are aware of the current decarbonisation targets set for 2030 but are monitoring a changing political environment and technology change before committing to decarbonisation projects. Incremental projects may occur in the 10-year period. Electrode boilers do not produce the higher temperature steam required for some industrial processes, and the economics aren't favourable at present. Customers are considering biomass in existing or new boilers or waiting for high temperature heat pumps where the coefficient of performance gives a circa factor of three reduction in the electricity load required.

System Growth

The System Growth category is dominated by expenditure in the following areas:

- 22kV conversion of distribution feeders (from 11kV) related to growth and voltage performance of rural feeders, including the ability to provide alternative supply during planned and unplanned outages. The programme averages circa $1.1m per annum over the period, is largely completed by FY2030, and has the added benefit of facilitating the renewal of all transformers and condition-based renewal of poles and pole-top hardware at the time of conversion.
- 11 kV Core Network Cables has lower levels of expenditure initially then ramps up to circa $0.6m per annum between FY2028 and FY2033. Refer to commentary below.
- Decarbonisation and New Technology allowance of $2m per annum, refer to commentary below.
- Installation of the new 66/11kV Tinwald Zone Substation transformer has been deferred from FY2028 until FY2030, due to the ability to use the Network Centres on the Tinwald side of the Ashburton/Hakatere River to supply load growth. This new Tinwald transformer will provide capacity and security to back up the Ashburton 66/11kV Zone Substation as load increases on both sides of the river.
- An additional double circuit 66kV line between Elgin and Fairton has been identified as required investment in FY2028 and FY2029 should network demand at Ashburton GXP exceed the secure 66kV line capacity to supply it.

11 kV Core Network Cables are the large capacity cables used to connect multiple 11 kV Core Network Centres over the Ashburton urban area. This expenditure is System Growth because these projects are intended to re-enforce capacity to growth areas and provide capacity for intensifying load, particularly if EV penetration levels increase peak loads in residential areas or in journey or destination charging locations.

Further comment on the timing of the 11 kV Core Network Centre projects is included below under Reliability, Safety and Environment – Quality of Supply.

The Decarbonisation and New Technology allowance of $2m per annum was provided for in past AMPs across the period to allow for the predicted need to respond to these types of network investments with uncertainty related to timing and expenditure levels. Within the period, activities have been identified and the expenditure required has been deducted from this allowance, resulting in the fluctuating expenditure in this allowance over the period. The following specific projects have been allowed for:

- Deployment of Powerpilot LV network monitoring equipment ($0.28m) in FY2025 using equipment already purchased, as a sentinel system to monitor:
  - Voltage performance of LV networks with small capacity cables, for load increase (e.g. EV charging).
  - Higher penetration single phase DG connections to monitor import and export, causing voltage rise in a subdivision with mandatory PV solar panel installation.
  - Higher capacity DG connections to monitor voltage rise in a subdivision with mandatory PV solar panel installation or on commercial PV sites.
  - Further deployment beyond FY2025 will be contemplated using results from these use cases and other use cases as developed. This will continue to draw down on the Decarbonisation and New Technology allowance.
- Connection of a new double circuit line between Elgin 66kV Zone Substation and Fairton 66kV Zone Substation in FY2029 and FY2029 ($2.7m) is assumed. Reconfiguring the Fairton Zone Substation for a second 22kV switchboard has also been assumed for FY2029 ($0.4m). This investment is driven by potential increased demand from the Fairton area from industrial growth (decarbonisation due to 2030 climate emissions obligations or new load connections).

GXP transformer cyclic overload capacity is adequate for expected load growth in the 10-year period. Ashburton 220 kV GXP is secure and resilient, allowing a single GXP to provide sufficient capacity and security. Transpower's prudent forecast is expected to be in excess of expected load beyond FY2034. This has resulted in the following outcomes in System Growth expenditure:

- The second Transpower GXP (connected to the Roxburgh – Islington A single circuit line) and associated 66 kV lines and substation connections required to connect the new GXP into the network at a cost of $4.2m has been deferred beyond the 10-year period.
- An additional double circuit 66kV line between Elgin and Fairton has been identified as required investment ($2.7m) should network demand at Ashburton GXP exceed the secure 66kV line capacity to supply it. The increased demand could be related to industrial decarbonisation, industrial load connection, or further large-scale solar generation connections in the northeastern part of the network. This investment will not proceed unless the network need materializes. Equally, if industrial load connects in other locations or large utility solar farm connections require reinforced subtransmission capacity in other parts of the network, this expenditure is indicative of the need for further capacity from Elgin out into the network.

Asset Replacement and Renewal

The majority of typical expenditure in asset replacement and renewal is:

- 11 kV and 22 kV overhead rebuilds; specific projects are identified by detailed network inspection early in the period, and budget allocations based on expected asset condition and less detailed network surveys are set for FY2027 onwards.
- Underground conversion of rural overhead lines where the ability to efficiently mole plough cables and a low frequency of connections makes cable installation more cost effective than overhead rebuilds.
- Underground conversion of urban lines at the point of renewal.
- Private Property Existing Shared Service Lines Policy for acquisition and renewal of shared lines on private property.

Underground conversion of urban lines at the point of renewal has been an ongoing programme of work for EA Networks. The replacement is condition driven and prioritized to ensure public safety (higher density of people close to network assets) and network reliability (higher customer counts) is maintained in urban areas. The AMP 2024 10-year programme has been normalised to manage resource workload and this has lengthened the programme by four years. Renewal projects involving concrete poles in urban areas have been deferred by several years, taking circa $2m out of the DPP4 period.

Underground conversion of the Lake Heron line has been included at $2m in FY2026. The cost of a non-network Remote Area Power System (RAPS) solution was costed in comparison, and on a lifecycle cost basis it was found to be of comparable cost, but required regular replacement of RAPS equipment, higher Operations and Maintenance costs due to a remote location. In addition, there are issues of needing to oversize PV panels and incur high diesel generation running periods in winter, particularly in a snow zone area. The visual and sustainability impact of RAPS installations in this high-country conservation area was also a consideration.

The 33 kV re-build of the Methven-Mt Hutt 33 kV line totals $1.5m across FY2028 and FY2029, this replacement is in line with condition but is a significant project within the overhead renewal programme.

Private Property Existing Shared Service Lines Policy for acquisition and renewal of shared lines on private property will introduce significant renewal capital, front loaded into the capital programme, on top of the initial allowance made in AMP 2023. This AMP 2024 budget has included the implications for expenditure and workload, with additional personnel required. The proposed capital will reduce the declining capital spend profile of AMP 2023, as seen above.

Private lines exist only on private property (only a Utility Operator may own network assets in public reserve land). EA Networks' connection policies over many years have required landowners to own the electricity assets (poles, conductor, and lines) on their property (this excludes transformers and other related equipment). This has generally been a non-issue, and the ownership demarcation point at the private property boundary is accepted. However, two recurring issues have begun to manifest as poles reach end-of-life:

- Maintenance and upgrade of private assets have not occurred in a timely manner, and
- Lack of clarity on ownership of some private lines with respect to regulation has become apparent.

Our teams have found that maintenance and upgrade recommendations of private assets have often been deferred by customers/landowners. Whilst this is at the landowner's discretion, we are not able to accept this where our assets (transformers) or wider network may be compromised because of this approach. Of particular concern are the poles that carry EA Networks' transformers since; our people climb these poles to effect repairs and undertake maintenance, and there is potential for asset and environmental damage should a pole fail and transformer oil escape.

To manage this situation, we have developed the following policies:

Private Property Existing Shared Service Lines Policy

This policy enables the transfer of these pole types when agreed with affected landowners. This policy seeks to progressively enable ownership of shared service lines to be transferred to EA Networks from landowners at a nominal cost of $1. Ownership transfer will only occur after an inspection and contractual agreement with the affected landowners.

This programme is forecast to be $0.2m in the establishment FY2025 phase, total $2.4m over the DDP4 period and taper down beyond that as the expected bow wave of poor condition lines are dealt with. This initiative totals $3.6m over 10-year period and has a full programme cost of $5.6M.

Item	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Pole Count	35	71	89	89	71	35	30	30	30	30

Table 3: Private pole shared service lines pole replacement forecast.

The operational expenditure funds the equivalent of two full-time staff to manage the inspection/research, negotiations with line owners, and necessary design/as-built records of the rebuilt line. These staff cover both the private property existing shared service lines and the private property existing transformer pole upgrade processes.

Private Property Existing Transformer Pole Upgrade Policy

This policy applies to existing transformer poles on private property (transformer being owned by EA Networks). Where an upgrade to the pole is required, and a landowner does not upgrade at their own cost, this policy enables our team to offer to upgrade at EA Networks cost on the basis that ownership is transferred to EA Networks. i.e. this policy acts as a back-stop to inaction by the landowner.

Ownership challenges

Depending on *when* a private line was installed, and the related agreements struck at the time, ownership can be hard to determine. Since EA Networks has always maintained that the private property boundary is the ‘network supply point’ (the demarcation point for asset ownership of poles, conductors, and cable) and the landowner was invoiced and consequently paid for all on-property works, our view is that all private lines are owned by the landowner from the network connection point.

We have received legal advice supporting this view, though it is recognised that each installation should be treated on a case-by-case basis. Where lines are shared (supplying more than one landowner) our private ownership position is more difficult. Regulation makes clear that these private lines should be owned and maintained by the network up to the point of common coupling (the point where a 1:1 relationship with a landowner can be identified). In general, there is a lack of good documentation that supports any ownership conversation, particularly when we look more than circa 15 years into the past. Reliance is placed on our prevailing connection policies, asset records and our approach to asset inspections on private property. At no time has EA Networks claimed ownership of poles, conductor, or cable on private property.

Reliability, Safety and Environment - Quality of Supply

Reliability, Safety and Environment – Quality of Supply is a category focused on reducing the number of interruptions or duration of interruptions seen by customers. Projects within this category include:

- Distribution automation for remote control operation, isolation of faults, and faster restoration of healthy portions of feeders.
- 22kV surge arrestor replacement programme to phase out a fault-prone surge arrestor type.
- Underground conversion for reliability of Methven Highway between Rooneys Rd and Springfield Rd.
- Replacement of the Ripple Control Converter Panel at Elgin Zone Substation spread over FY2026 and FY2027 at expected end of reliable life (20 years in line with industry experience and manufacturer’s recommendation). This combined with the new Elgin primary coupling cell (order placed, for installation in FY2025) will provide a new ripple control plant at Elgin capable of maintaining hot water and street light control for the whole network should the older Ashburton ripple control plant fail. It will also provide a spare parts reservoir for the older plant from the decommissioned Elgin ripple control equipment.
- 11 kV Core Network Centres related to segmenting urban feeders in Ashburton to reduce the customer reliability impact of cable faults by reducing the number of customers per cable fault and providing more alternative feed capacity during faults and planned work.

The 11 kV Core Network Centre (Quality of Supply) and 11 kV Core Network Cables (System Growth) projects have not advanced as planned in FY2024. In FY2024, the switchgear type was confirmed (this required a due-diligence investigation of some type failure events on another distribution network with the switchgear), but the remainder of work to secure access to sites and complete design and route planning was not completed. This was due to internal engineering focus on the Lauriston Solar Project (to connect the Lauriston Solar Farm) and ANZCO supply upgrade. Hence, expenditure in FY2025 will be to secure access for the remaining network centre sites and complete design and route planning. Since some of the core network cable and network centre projects are driven by growth in load and customer numbers yet to materialize, the phasing of the component projects has been reprioritised across the 10-year period, with circa $3m deferred beyond FY2030.

Reliability, Safety and Environment – Legislative and Regulatory

This is a small two-year programme in FY2025 and FY2026 totalling $0.24m to improve clearances between network lines and Transpower transmission lines to regulated clearances.

Reliability, Safety and Environment - Other

The majority of the expenditure in this category has a safety driver, with the following components:

- Distribution substation earthing upgrades: a routine programme of testing and upgrades for public safety across the period.
- Private Property Existing Transformer Pole Upgrade Policy involving the replacement of on-property transformer poles.

Private Property Existing Transformer Pole Upgrade Policy, involving the renewal and ownership of on-property transformer poles, is a safety driven programme related to the risk faced by EA Networks field workers climbing transformer poles on private property. EA Networks' ownership position of lines on private property has been that on-property lines are owned by the landowner. As noted above, landowners are either unaware of their ownership or inadvertently leave overhead lines to fail before addressing their poor condition. The issue with transformer poles is that this exposes EA Networks field workers to risk when climbing these poles (that are already loaded with a transformer), and they do so with a greater frequency than poles that simply support conductors. Other considerations are the exposure of the EA Networks owned transformer to failure, and the environmental contamination that results if a transformer leaks when the pole fails.

This programme is forecast to be $0.5m in the establishment FY2025 phase, total $4.8m over the DDP4 period and taper down beyond that as the expected bow wave of poor condition lines are dealt with. This initiative totals $7.1m over 10-year period and has a full programme cost of $11.7M.

Item	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Pole Count	45	91	114	114	91	39	39	39	39	39

Table 4: Private pole existing transformer pole replacement forecast.

Non-network Assets

Non-network Assets includes expenditure on the following:

- Vehicles: EA Networks has deferred replacement of vehicles in recent years, so expenditure in this area is higher than normal for FY2025 as this backlog of replacements is dealt with.
- Corporate – IT hardware (90% allocation) and network equipment (100% allocation) to network costs.

AMP 2024 10-year Operational Budget

A review of all network operational budget categories against the last five years of historical spending has resulted in revised levels of expenditure in the operational budget. The operational expenditure on maintenance activities has also been critically reviewed to better match the field resources available to complete the work at the current and expected rates.

Other Specific Initiatives

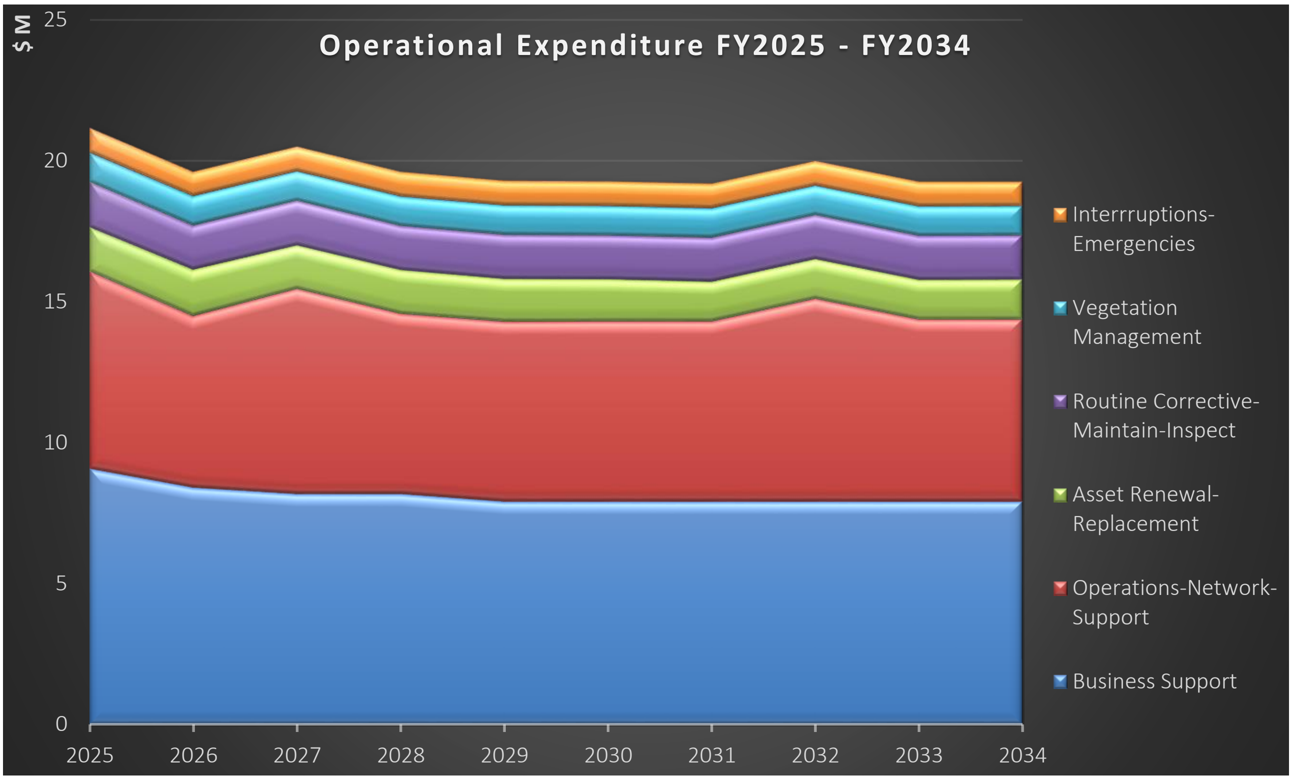
The following specific initiatives have been included in the AMP 2024 10-year Operational budget, with varying implementation dates and phased introduction according to need:

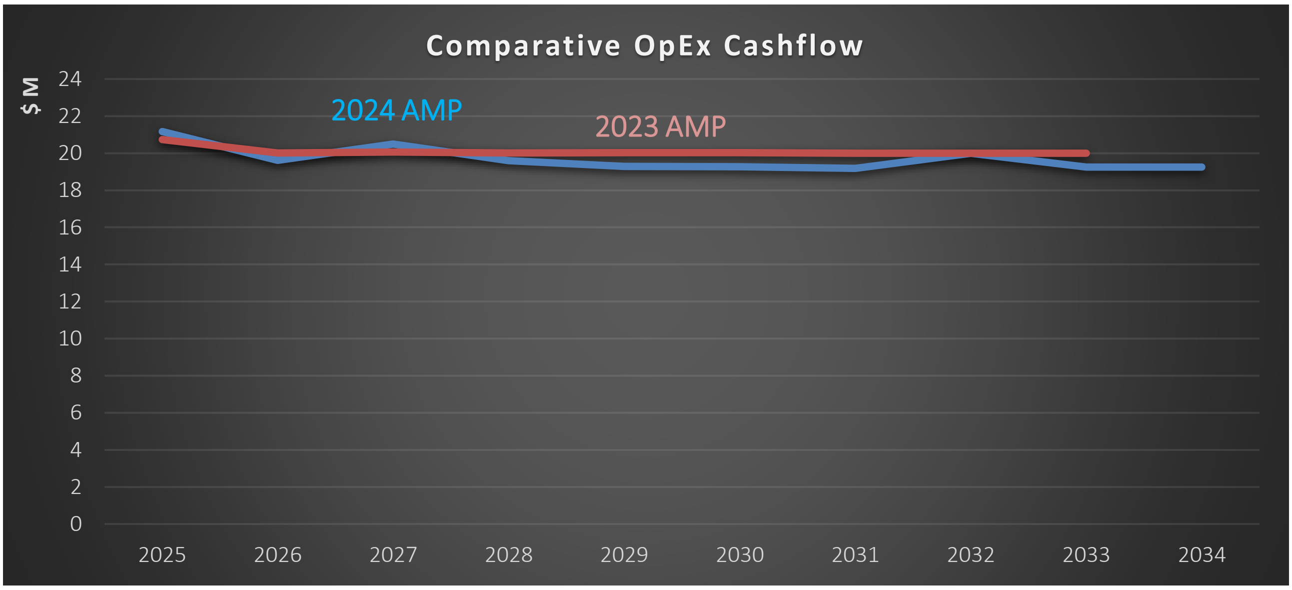
- LV Meter Data: Purchasing and resourcing customer low voltage meter data low to provide greater insight into the low voltage network. This is a sentinel system to identify issues with LV network circuits and connections for safety, voltage compliance, LV or distribution transformer capacity issues and phase loading imbalances which may be driven by organic growth and EV penetration for example.
- Private Property Existing Shared Service Lines Policy and Private Property Existing Transformer Pole Upgrade Policy Programme: Operational costs to support the Programme in a programme manager, lines inspection, design, and work pack preparation resource.
- Engineering, Communications, and Analysis Resource: expected additional people resource investment providing capability in Engineering and asset management (regulatory, operational and investment efficiency, and complex digital network drivers), Communications to stakeholders (regulatory, customers, community) and Analysis to support continuous improvement and identify commercial and operational efficiencies.
- Advanced Distribution Management System (ADMS) Development: Continual upgrade and development of ADMS system to meet the future requirements of a future-fit, digital distribution network. This is aligned to EA Networks' intention to build capability to match the ENA Network Transformation Roadmap and meet the future needs of connected customers and the electricity industry related to decarbonisation of process heat and transport, connection, and management of Distributed Energy Resources (e.g., utility scale solar and smaller scale distributed generation) via DERMS, demand flexibility, distribution system operator functions, etc.
- Considering the implementation of a Human Resource Information System (HRIS)
- Considering the implementation of a Document Management System (DMS) to improve management of documents, drawings, and other forms of data in a centralized way to reduce inefficiencies, maintain intellectual property, and ensure secure, persistent, versioned, and controlled data management appropriate for a long-term infrastructure and asset management business.
- Enterprise integrations/management: Investment in enterprise system integrations and management to enable an efficient, digital work environment.
- Pricing & Harmonic ICP Inspection Programme: Establishing a programme to ensure customer capacity matches pricing and monitoring of harmonics via field surveying and updating of records. Harmonic levels on the network and aggregated back to the Ashburton 220kV GXP are significant due to the high penetration of irrigation pumps and dairy milking plant load. At present, the harmonic voltage distortion levels at Ashburton GXP 66 kV busbar exceed ECP 36 (the mandated standard). The origin of this distortion is not clear, but EA Networks need to actively monitor known harmonic distorting loads to ensure customers comply with our harmonic standards, thereby controlling harmonic distortion to pragmatically low levels.

Forecast Operational Expenditure – Schedule 11b

The overall operational expenditure forecast is largely similar to the previous (2023 AMP) forecast. The future forecasts show a small initial rise in both categories of non-network expenditure followed by a gentle decline. Sporadic bumps in network support expenditure occur when significant software upgrades occur (such as ADMS development). There are smaller rises in network expenditure, most notably vegetation management.

Note that the costs are shown in 2024-25 dollars and exclude CPI adjustment. The disclosure schedules at the end of the document include inflation adjusted cashflows.





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, apart from the aspects mentioned in this section. A detailed account of changes to the approach to network risk assessment and management, and an assessment of resilience management maturity and an improvement action plan for resilience have been described in subsections below.

The TechnologyOne work order management / asset management system is maturing and a Financial Improvement Project has commenced in late 2023 to update and systematise the methodologies used to manage the electricity assets and management of work and finances. A future AMP will detail any material changes that are planned or occur.

The external review of asset management processes completed in 2022 is resulting in continuous improvement changes to asset management practices, and this will be documented in the next full plan. This includes work on asset health indicators for various asset classes and an update to the Safety in Design process.

Network Risk Register Update

EA Networks' previous engineering risk register was last fully reviewed in 2000. As a result, the Cosman Parkes Ltd Health & Safety Maturity Assessment identified an action to update the risk associated with the network. This section describes the process and results of the update.

The resulting Network Risk Register update has completely re-formulated the approach to network risk, with a full risk register considering risks related to health and safety, the environment, impacts on stakeholders and impacts of asset failures on network reliability and the cost of replacement/reinstatement. The risk register is formulated in line with the EA Networks Risk Management Standard.

The register contains 106 separate risks, with a High Focus Network Risk report selecting ten risks with a residual rating of Very High for entry onto a heat map. All other risks have a residual rating of High or lower.

Approach to Updated Network Risk Register

EA Networks has a set of 13 organisational critical risks, that appropriately summarises the critical risks at a high level by type. Of those critical risks, the following risks are explored in more detail in the Network Risk Register:

- Public Safety.
- Disaster.
- Significant Unplanned Outage.
- Critical HSE Risks (this takes more of a field operations view on risks, while the Network Risk Register identifies these through a network and asset lens).

The structure of the network risk register follows that used by two other EDBs, with risk categorised into Assets Failure and Operations or Environment and Stakeholder, for each of the four following asset-based categories:

- Overhead Lines (Sub-transmission, distribution, and low voltage)
- Distribution substations, switchgear, and underground assets
- Zone substations
- Other (comprising a variety of risks including GXP and Elgin 66kV bus risks, secondary systems like communications and SCADA, environmental risks like flooding, earthquake, high winds, snow, and stakeholder risks including power quality)

For a number of reasons, a detailed risk register approach has been selected, instead of a more generic critical risk approach. These reasons are:

- A detailed approach related to asset types and in cases specific situations (e.g. bridge failures that impact on network cables) allows the impact of those risks to be considered specifically, controls identified, and an assessment made if further controls are needed or possible.
- Treatment of detailed risks contributes to organisational resilience, particularly related to reduction, readiness, and response, not only to emergency events from natural disasters but also asset failures and third-party interference. This can be achieved more comprehensively with a detailed risk register.
- Recording the assessment of risk rating, controls and further actions required with periodic review ensures risk management disciplines are structured and can be revisited when circumstances change or more information is available. This record also is helpful when investigating events and

incidents, to understand what the analysis and position of the organisation was in relation to controls that may be in place or under action.

Risk Review Process

The network risk register is spreadsheet based, allowing easy workshopping, review, and update by teams of subject matter experts. The base risk register was prepared by updating the specific likelihood probabilities/return periods, the consequence ratings, and the risk assessment matrix in line with EA Networks' Risk Management Standard, which is shown below for reference. Risks are rated in an inherent condition, without controls. In a number of cases where network configuration and asset types are existing, the inherent condition includes historical design and construction decisions when the asset was installed that act as controls. Abstracting from the status quo is largely impractical. The existing controls are listed, and the risk rated at a residual level. The residual risk assessment is evaluated as:

- Effective if within tolerance, ALARP and good industry practice, or no further controls are considered feasible.
- Improving if further action to implement controls are underway.
- Further Controls Needed if additional controls are recommended and no action is yet underway.

Risk review workshops were held with an expert team, with focus of their expertise on specific asset classes. The length of tenure and experience of the team both within EA Networks and elsewhere in the distribution sector was of great assistance in tuning risk descriptions to the most credible worst-case scenario, and assessing the likelihood based on past instances of the risk materialising (or not).

The initial set of risks within the register came from another EDB, and the review workshops customised or eliminated the existing risks. There was a great deal of commonality in risks due to common asset types and failure modes etc. Environmental factors specific to Mid-Canterbury were added, such as snow, the extreme AF8 Alpine Fault scenario, the potential Ashburton Bridge failure affecting the network and larger areas of network exposed to flooding. Other network specific factors were added related to harmonics from irrigation pumping, irrigation load patterns, and both network configuration and GXP security.

Analysis of Network Risks with the Register

The following table shows the breakdown of the risk register entries into categories.

Asset Category	Failure & Operations	Environment & Stakeholder	Total
Overhead Lines	12	14	26
Distribution Substations, Switchgear, & Underground	16	13	29
Zone Substations	18	12	30
Other	11	10	21
Total	57	49	106

In overview, the following observations can be made about the network risk register:

- Risk types and outcomes are not out of step with other electricity distribution networks in New Zealand like Network Waitaki, Waipa Networks, and Powerco. In a number of cases, risk exposure to reliability events is lower because of the largely ringed sub-transmission network, the ability to back-feed and back up zone substations, and relatively low ICP counts on feeders. Relatively recent network upgrades and voltage conversions means that the overall network condition is better, reducing asset failure with both reliability and safety risk.
- That said, because of the ubiquity of network assets within places accessible to the public and supplying workplaces etc. and the network role as an essential service, there is an unavoidable degree of safety and reliability risk related to essential distribution infrastructure. Undergrounding

of assets in state highway road corridors and urban areas is reducing this risk, and it is lower than many other networks as a result.

- There are more risks related to zone substations than other asset classes because of the increased complexity and diversity of equipment, and the higher impact of key equipment like zone substation transformers and switchgear.
- Distribution Substations, Switchgear, & Underground are not inherently riskier, but the higher risk count relates to the combination of a number of asset classes into this category.
- The risk register is not intended to be completely exhaustive. The intention is to cover material risks, particularly with a high inherent risk ranking, and ensure appropriate controls are applied to reduce risks to an **A**s **L**ow **A**s **R**easonably **P**ossible (ALARP) level. This will include assessment of likelihood, impact, practicality, and economic viability of controls in line with good industry practice.

High Focus Residual Risk Summary

Due to the high number of risks within the risk register, it is necessary to focus attention on a manageable number of the highest residual risks so control improvement is prioritised. Review of the risk register identified the best High Focus Risk category to be risks with residual rankings of Very High, which results in a High Focus risk category containing ten risks. The Network High Focus Residual Risks are shown in a heat map for management and Board reporting. For eight of the risks, the inherent and residual risk assessment is the same. This is because, in spite of controls applied, it was decided that the consequence and likelihood had not changed to within the next classification.

Resilience Management Maturity Assessment and Resilience Action Plan

This section provides a commentary on EA Networks' EEA Resilience Management Maturity Assessment Tool RMMAT assessment and notes areas for inclusion for improvement in the Resilience Action Plan dated February 2024. This is the first time that EA Networks has completed a RMMAT assessment, so the commentary here has not been provided in past AMPs.

Work completed since the first RMMAT assessment in July 2023 has shown improvement in a number of areas (particularly in risk identification, assessment, and documentation) with the completion of the Network Risk Register and associated action plans. By collation of a resourced and detailed Resilience Action Plan, EA Networks have instigated a structured approach to improving resilience management. The action plan makes a commitment to improvement of resilience that will enhance EA Networks' emergency response capability during events by a better and more balanced approach to the 4Rs of Reduction, Readiness, Response and Recovery.

The Resilience Action Plan focuses on the following areas for improvement:

1. **Reduction:** Areas targeted are in more detailed assessments of major risks, lifelines engagement, network and critical spares management, and contingency planning for major and likely scenarios.
2. **Readiness:** Improvements will be made to capability in business continuity management, contingency planning, communication plans, and contract resourcing.
3. **Response:** A focus on the areas of response systems and processes, as well as EA Networks' generation capability when working with Ashburton District Council on their generation plans at community hubs and critical sites.
4. **Recovery:** This is an area where current capability is quite weak, but development of a recovery strategy, recovery plan, and stakeholder communications and consultation plans modelled on a good industry example from our industry peers will be completed and will quickly lift capability in this area.

The re-scored RMMAT assessment and the three-year improvement plan will be included in the 2024 AMP, with a forecast of what the RMMAT assessment scores are expected to be at the completion of the action plan. The expected outcome is shown in Figure 4 below, a well-rounded and balanced approach to resilience across reduction, readiness, response, and recovery. Capability will be developed and implemented via this resilience action plan and gaps in our current capability will be addressed.

Background

ENA (Electricity Networks Aotearoa) instigated a focus on resilience in response to increased industry, regulatory, and government attention on critical infrastructure resilience stemming from the recent extreme weather events impacting electricity supply, in particular Cyclone Gabrielle. In July 2023 ENA requested member EDBs to complete the EEA Resilience Management Maturity Assessment Tool (RMMAT) and submit their scoring for collation and analysis. ENA EDBs were also requested to include the RMMAT assessment in their 2024 AMP. As at 19 July, 17 EDB had submitted their RMMAT assessment (including EA Networks) and the median results are provided below in Figure 2.

EA Networks RMMAT Assessment

The EEA RMMAT assessment is included in the EEA Resilience Guide, first published in November 2020 and further reviewed in July 2022. The resilience assessment is based around the 4R's (Reduction, Readiness, Response and Recovery) of emergency response as set out in NZ's CDEM framework.

The RMMAT assessment is 72 questions across 19 functions that allow organisations to self-assess their level of resilience management maturity. The RMMAT scoring system is as follows:

Maturity Level		Maturity Description
0	Not Aware	The organisation has not recognised the need for this requirement, and / or there is no evidence of a commitment to put it in place.
1	Aware	The organisation has identified the need for this requirement and there is evidence of an intent to progress it.
2	Developing	The organisation has identified the means of systematically and consistently achieving the requirement and can demonstrate that progress is being made with credible, and resourced plans in place.
3	Competent	The organisation can demonstrate that it systematically and consistently achieves relevant requirement. Only minor inconsistencies may exist.
4	Excellent	The organisation can demonstrate that it consistently exceeds the requirement. It employs and fosters leading local and international industry practices and has a mature continuous improvement culture to ensure a high standard of maturity and compliance is maintained.

Hence it can be seen that to have a competent maturity level, a score of 3 in all 19 functions (perhaps with some exceptions as discussed below) would be required.

It is easiest to visualize EA Networks' current state of resilience management maturity by the following radar diagram (Figure 1), showing the current score for each of the 19 functions, arranged by the 4R's.

By way of comparison, the radar diagram in Figure 2 is the median RMMAT scores as received by ENA as at 17 July 2023. In some areas the media score is higher than EA Networks' score but there are a number of areas where the maturity score is the same. Hence it can be seen that EA Networks has room for improvement, comparing Figure 2 with current maturity in Figure 3, but is not greatly out of step with industry peers.

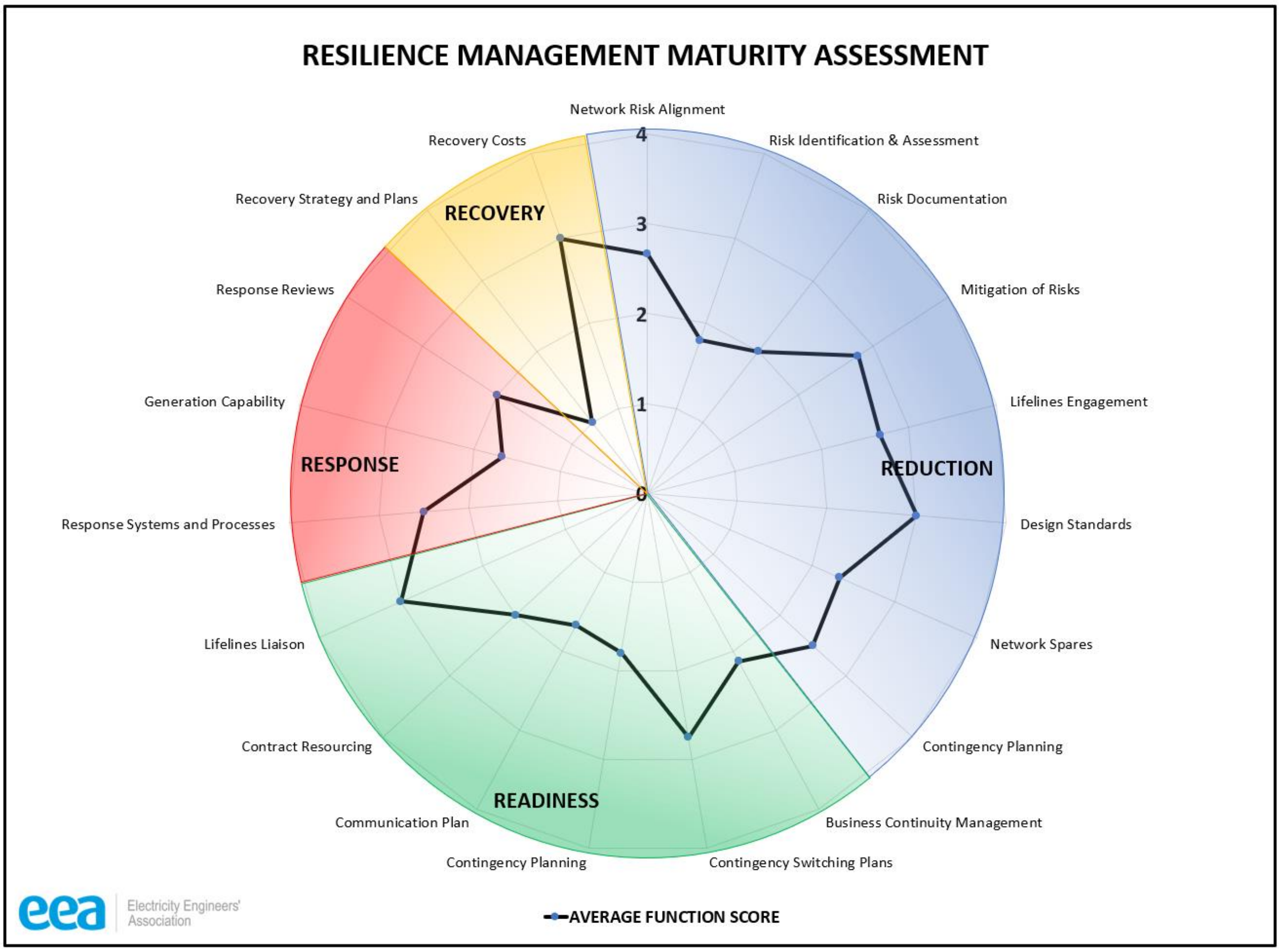
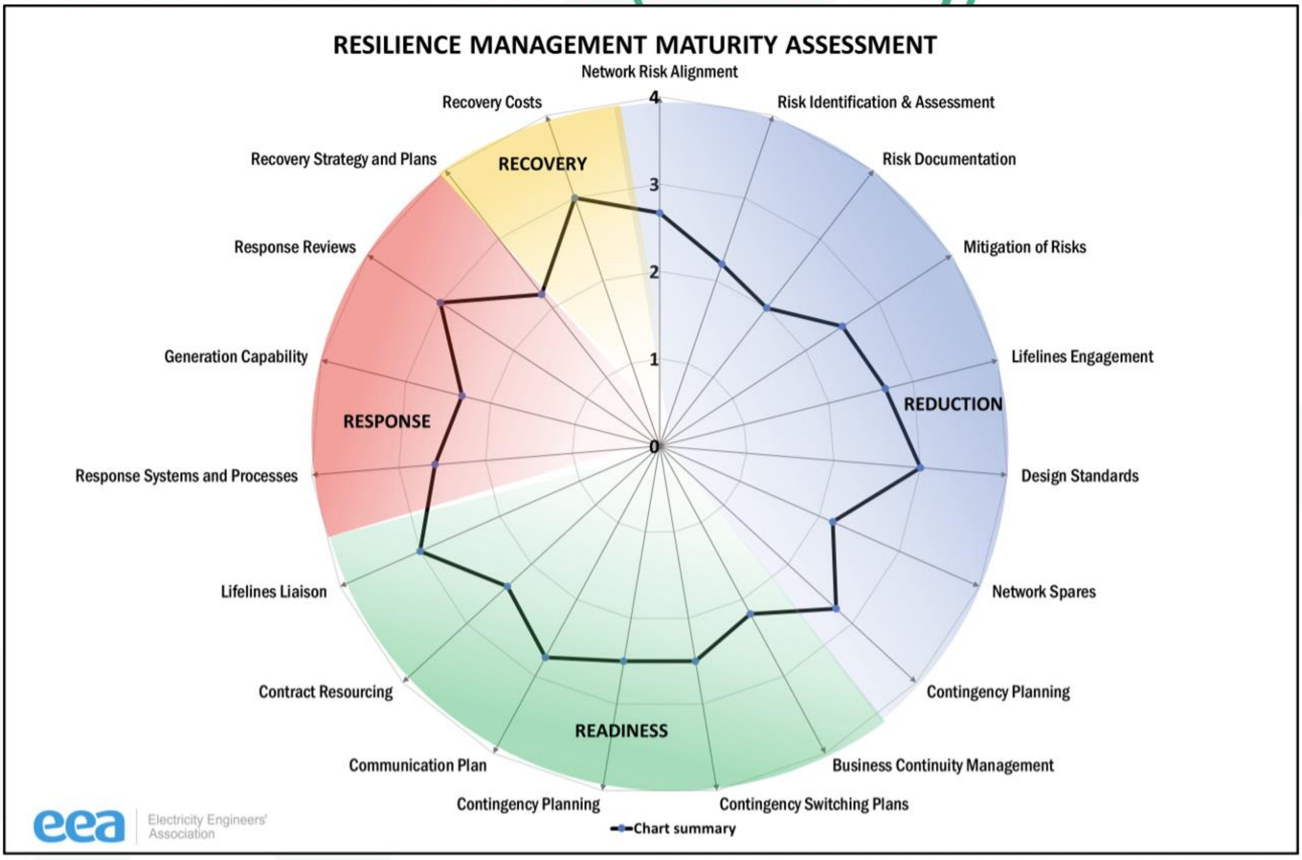


Figure 1: EA Networks July 2023 RMMAT Scores

Median RMMAT Scores (as at 17 July)



Source: ENA, calculated from member's self-assessment

Figure 2: Median RMMAT Scores from 17 ENA member EDBs

Commentary on EA Networks' RMMAT Assessment

In the majority of the 19 functions, EA Networks scores below a competent level. However, the following observations are helpful:

- In a number of Reduction functions related to risk, scores have increased now that the network risk register has been re-populated, completed in August 2023.
- Scores can be lifted from 0 or 1 to 2 by means of designing the solution and putting a resourced plan in place. Hence a resourced, detailed improvement plan (the Resilience Action Plan) has lifted scores for the 2024 AMP RMMAT in a number of areas as a result of this planning work.
- In some areas EA Networks policy may be to not match the recommended RMMAT capability. For example, in the Generation Capability function, one measure is if generation capacity is contracted in advance to bring in during events. Our current policy is not to provide generators to customers, and to encourage customers that if electricity is essential to their ongoing operations, they should make their own arrangements. If it was known that EA Networks would provide generators under emergency situations, it's likely that customers would rely on that instead of making rational decisions related to their own circumstances. A second example is related to contingency planning, where the assessed maturity approach is to contract with a structural engineer to respond to a request for seismic assessments following an earthquake event. This service has been costed (an annual retainer) and was considered not good value for money compared to the likelihood of calling on the service. Instead, it is expected that a request to CDEM to allocate a structural engineer to assess our critical infrastructure buildings will be sufficiently prioritized as an alternative approach.

EA Networks’ February 2024 RMMAT Assessment

EA Networks has completed further resilience improvement actions along the lines of the above commentary. As a result, the February 2024 updated RMMAT scores are summarized in Figure 3.

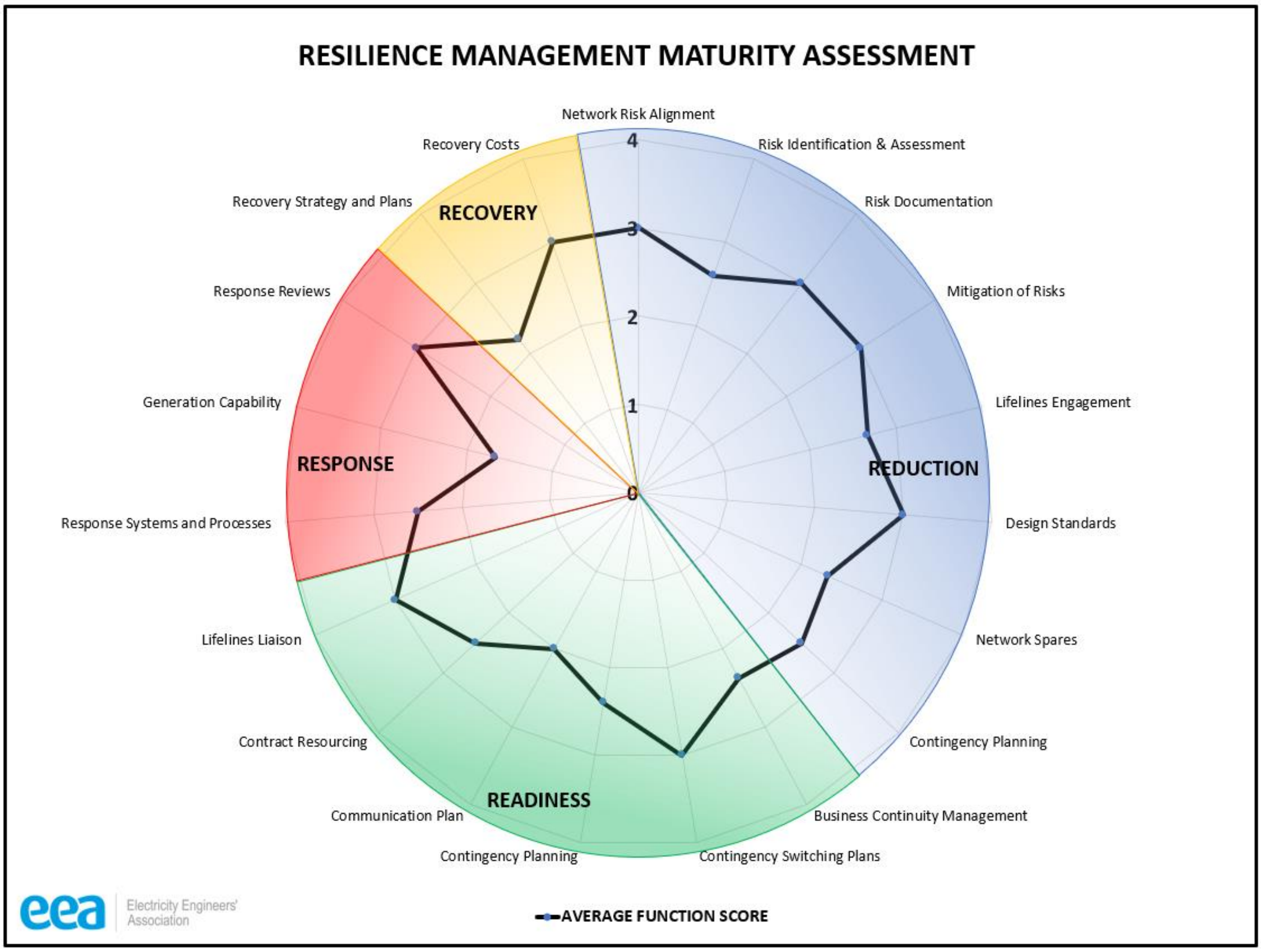


Figure 3: EA Networks February 2024 RMMAT Scores

EA Networks Resilience Action Plan

Actions for inclusion in the Resilience Action Plan where we will lift capability in a meaningful way and cover gaps in our capability are as follows:

Category	Action Planned	Phasing within the Plan
1. Reduction	Identification and Mitigation of Network Vulnerability Risks	
Risk Identification and Assessment:	Prioritise and document risk control plans for high focus risks related to emergency preparedness, asset and systems related vulnerabilities, and natural hazards.	FY25, FY26, FY27
Asset Criticality Framework:	An asset criticality framework will be developed with reference to the EEA Criticality Guide, to classify asset classes and particular equipment into criticality grades. This will assist in quantifying vulnerability and consequence metrics from a network resilience perspective.	FY27
Network Spares:	EA Networks has reviewed critical spares against asset types and commenced reviewing critical spares holdings and storage. A wider review of critical, emergency, and operational spares requirements is	FY25, FY26

	underway but needs to be completed, including documenting what spares are held and where they are stored, what critical spares and volumes required to be held, what procurement is needed based on gaps identified, and budget provision made for that in the AMP. Seismic security and strapping needs to be assessed. Sub-transmission lines stock is maintained for the ongoing build work and emergency response. Further work is needed to complete a risk analysis of how much stock would be needed in the credible worst-case scenario. Documentation of our network spares and critical spares approach is required.	
2. Readiness	Pre-Event Contingency Planning and Training	
Ongoing CIMS improvement:	Roles, exercises, and coordination with CDEM and other lifelines organisations. Focus on organizational resilience related to business continuity (logistics, systems, IT, and communications).	FY25, FY26, FY27
CDEM Liaison:	Coordination with ADC regarding resilience and emergency preparedness.	FY25
Business Continuity Management:	Analysis of the performance of critical business systems, applications, functions, processes and services, and identification of agreed recovery timeframes with the relevant business owners. Cover ERP/EAM, SCADA/ADMS, GIS, Stores/procurement, and Network Information.	FY26
Business Continuity Management:	Review supplier and out-sourced service provider dependencies, including contractual responsibilities are in place to support critical services. Vegetation contractors have informal engagement to respond for emergencies - Vegetation Management RFP should improve the formality of this. Implementing emergency response traffic management service contract. Related to stores and procurement of network materials, there are standard procurement arrangements in place, but no specific contractual arrangements related to business continuity.	FY25, FY26
Contingency planning:	Document high risk/critical scenarios e.g. major Ashburton flood, ASB 220kV/Elgin faults, major snow or windstorm, bridge or key roading access failures, and earthquake including AF8. Seek experience in past events from other EDBs etc.	FY25, FY26, FY27
Contingency planning:	Seismic assessment contract in place for post-earthquake assessment; identify providers as part of contingency plan. Revisit phasing for seismic assessment and remediation programme for zone substation buildings and consider more rapid roll out. Seismic assessment retainer not considered value for money, check approach with CDEM of seeking allocation of a structural engineer for critical infrastructure and buildings.	FY25
Contingency planning:	Contingency Plans for critical staff such as NOC Controllers. EA Networks is involved with Westpower, Mainpower, and Powerco as OSI SCADA/ADMS users and have begun planning for cross-functional training and harmonisation of operating procedures to allow network controllers to move between control rooms in a major event. Considering training more duty controllers to cover this skilled position. A fuller review of contingency planning and alternative locations is	FY25, FY26, FY27

	required, including an alternative control room (potentially equipping a desk at Westpower, Methven, or at Ashburton Zone Substation).	
Generators:	EA Networks existing generation covers JB Cullen Drive, Ashburton Substation, Gawler Downs, Round Top, and Ashburton radio repeaters all with permanently connected generators. Purchase a generator for the Methven Substation to support that important node. Assess need for contingency control room in a container connected to power, generator plug, and communications. Potentially stored at Methven Substation and can be relocated where needed depending on the contingent event. Transpower Ashburton 220kV GXP is another potential back up control location. Consider the scenarios where this would be required and assess justification.	FY26
Generators:	Evaluate critical sites for generation to be connected to and work with Ashburton DC CDEM function and stakeholders to prioritise and develop plans for generator plugs and generator supply by users, including: • ADC Critical infrastructure, CDEM welfare centres, Hospital, Medical centres, Supermarket(s), Service station(s), at least one ATM, Mobile cellular sites, Other data solutions – Starlink Hinds base station resilience, Schools, Other essential contractors who need depot electricity.	FY25
Generators:	• Investigate feasibility of tractor PTO generators. Liaise with ADC CDEM if this is a useful lower cost solution, e.g. for mobile cellular sites or smaller critical sites like medical centres. • If EAN supplied generators, need to secure them from theft and re-fuel them which also consumes resources (look for support contractors to do re-fuelling).	FY25
Reduction and Readiness:	Bridge dependencies: Need to consider the resilience and redundancy of the above critical sites north and south of the Ashburton River.	FY25
Emergency Incident Communication Plan:	Currently there are communication tasks/methods for use during emergencies, but no overall communication plan. Communications are briefly mentioned as part of the Public Information Manager role in the CIMS structure. Obtaining a good example of a Communication Plan from one of our peer EDBs and customising it would be an easy way to implementing this capability. When combined with implementing customer outage communication via the ADMS Outage Management System and Salesforce customer contact records, this will lift capability in this area. The plan will have a regular review cycle.	FY25
Contract Resourcing:	Improve interoperability, make plans for bringing in external resources and ensuring they can be housed and fed. Working hours / fatigue management policy to be developed and implemented.	FY25, FY26
3. Response	Immediate Actions Following an Event	
Response Systems and Processes:	Improving our Response Systems and Processes will improve our effectiveness in an emergency event. Work is underway to develop the ADMS Outage Management System and customer communications capability (Phase 1 due March 2024 for planned outages, unplanned	FY25, FY26

(Outage Communications)	outages to follow in FY25). The ability for administration staff to take outage calls and enter them into the ADMS is being developed to scale up our ability to respond to larger events. Review and solution for volume of fault calls, e.g. call avalanche system to off-load controller/call takers or other solution. Budget and phasing to be determined in FY25 for potential implementation in FY26.	
Emergency Incident Communication Plan:	Include thresholds for enacting the customer/stakeholder communication response plan.	FY25
Generation Capability:	In conjunction with the generator planning work with Ashburton District Council, document a generator deployment process for emergency diesel generators and suitable leads for critical sites and long-repair time damaged networks.	FY25, FY26
Response Reviews:	Document how EA Networks uses the appreciative inquiry method (What worked well? What didn't work so well? What can we improve?) for major and extreme events. These trigger lessons learnt summaries and improvement actions. Define the thresholds that constitute a major and extreme event that would then require a response review. Will be completed when the draft Standard - Emergency Preparedness Part 2 Extreme Events is finalized.	FY24
4. Recovery	Long Term Reinstatement of the Network	
Recovery Strategy and Plans:	The recovery phase is where the immediate response to an emergency is completed, and the longer-term tasks of restoring the network to a satisfactory state are now required. This may involve "building back better" given the lessons of the emergency event, consulting with affected communities where the emergency has fundamentally changed their needs or occupation of the land, determining longer term refurbishment or replacement of assets where temporary repairs have taken place. Obtaining a good example of a recovery strategy and plans (ask Westpower, Orion…) and adapting for our use is a pragmatic way to progress this. Documentation of communication plan and stakeholder consultation and engagement plan. Consider management of potential regulatory compliance issues. Draft in FY25, further development over FY26 and FY27.	FY25, FY26, FY27

In terms of resourcing for the above action plan, in general the improvement actions will be resourced by internal people mostly from the Network and Field Services teams, and in the Customer and Commercial team related to specialist aspects like customer communications and stakeholder engagement, IT, and business systems etc., drawing on in-house expertise. Involvement of Ashburton District Council's CDEM team and Infrastructure team will be required. Consultation with external experts e.g. for seismic or wildfire risk assessment etc. will be completed as needed. A small amount of budget will be allocated for the work from within the wider consultant expenditure and, where necessary, network and non-network budget will be approved within the Asset Management Plan approval process. It should be noted that in the case of network capital expenditure, a number of projects already planned within the 10-year capital forecast will have a resilience benefit, hardening the network through asset renewal, improving reliability from undergrounding overhead network or improving security by redundancy, switching and configuration improvement, and network automation.

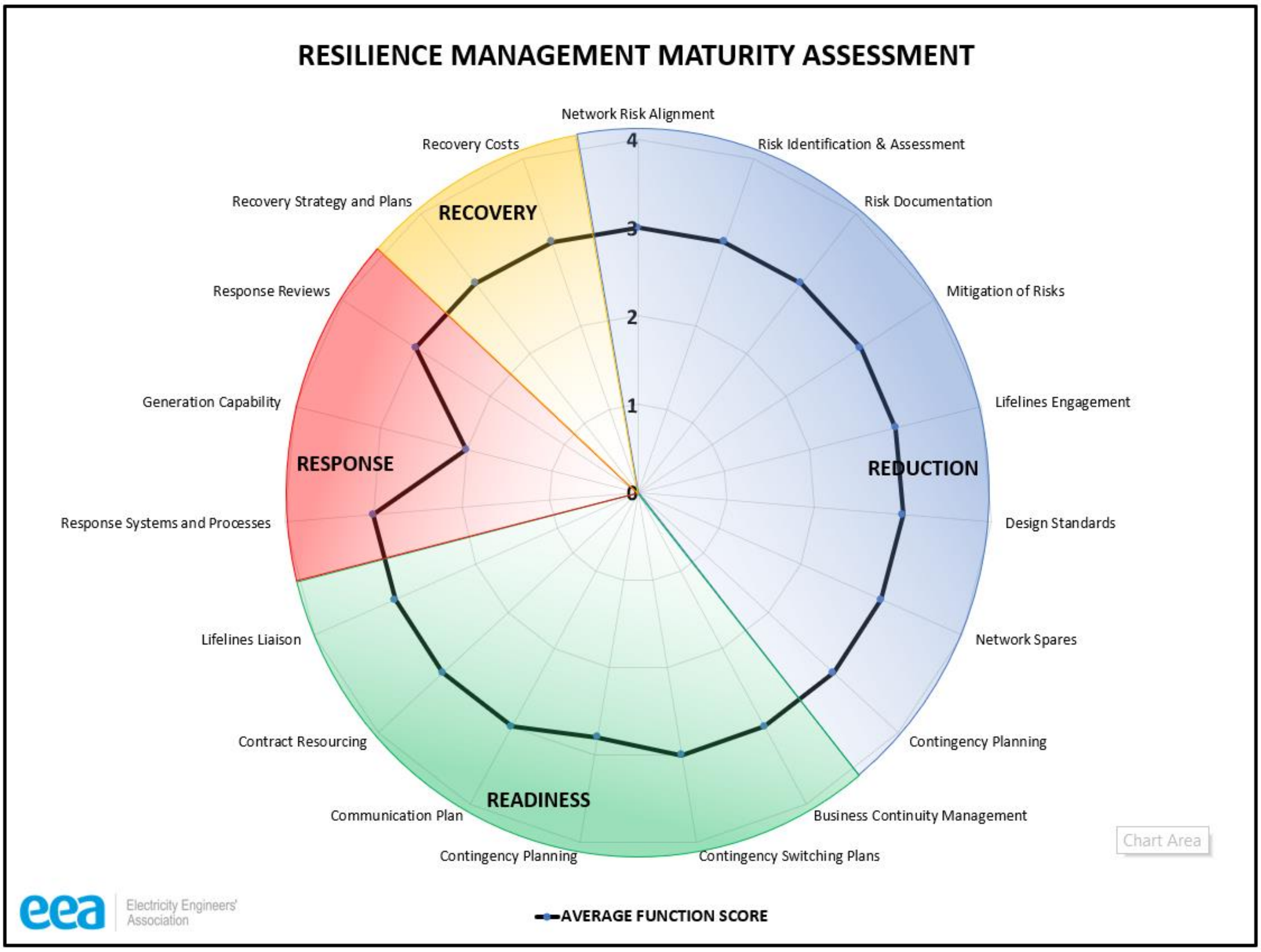


Figure 4: EA Networks FY27 Forecast RMMAT Scores

EA Networks' Forecast FY27 RMMAT Assessment

By completing the above Resilience Plan, we expect that RMMAT scores will be improved as shown in the above radar diagram (Figure 4). This shows a well-rounded and balanced approach to resilience across reduction, readiness, response, and recovery. Capability will be developed and implemented via the above action plan and gaps in our current capability will be addressed.

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 2024 and, where necessary, forecasted/ scaled to reflect the full 2023-242 disclosure year.

Schedule 11a Report on Forecast Capital Expenditure

Company Name	EA Networks (Electricity Ashburton Ltd)
AMP Planning Period	1 April 2024 – 31 March 2034

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). EDBs must express the information in this schedule (11a) as a specific value rather than ranges. Any supporting information about these values may be disclosed in Schedule 15 (Voluntary 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												
9	**11a(i): Expenditure on Assets Forecast**	**$000 (in nominal dollars)**										
10	Consumer connection	3 714	6 557	4 108	3 742	5 776	3 751	3 811	3 990	4 051	4 171	4 274
11	System growth	2 841	3 262	4 024	4 085	4 534	4 805	6 767	2 960	3 660	3 500	2 929
12	Asset replacement and renewal	7 780	6 785	8 187	4 819	4 548	4 826	4 368	4 450	4 642	3 508	3 733
13	Asset relocations	17	-	-	-	-	-	-	-	-	-	-
14	Reliability, safety and environment:											
15	Quality of supply	125	1 297	1 379	1 303	944	538	179	550	332	92	786
16	Legislative and regulatory	-	119	121	-	-	-	-	-	-	-	-
17	Other reliability, safety and environment	397	630	1 123	1 434	1 449	1 230	613	641	651	670	687
18	**Total reliability, safety and environment**	522	2 046	2 623	2 737	2 392	1 768	792	1 192	984	762	1 473
19	**Expenditure on network assets**	14 874	18 651	18 942	15 383	17 251	15 150	15 739	12 592	13 337	11 940	12 409
20	Expenditure on non-network assets	824	778	344	762	830	722	718	732	747	1 438	777
21	**Expenditure on assets**	15 698	19 428	19 286	16 145	18 081	15 872	16 456	13 324	14 084	13 378	13 186
22												
23	*plus* Cost of financing	-	-	-	-	-	-	-	-	-	-	-
24	*less* Value of capital contributions	1 379	5 604	1 133	513	2 328	480	480	480	480	480	480
25	*plus* Value of vested assets	-	-	-	-	-	-	-	-	-	-	-
26												
27	**Capital expenditure forecast**	14 319	13 824	18 153	15 632	15 753	15 392	15 976	12 844	13 604	12 898	12 706
28												
29	Assets commissioned	14 319	13 824	18 153	15 632	15 753	15 392	15 976	12 844	13 604	12 898	12 706

30		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
31												
32		**$000 (in constant prices)**										
33	Consumer connection	3 714	6 557	3 958	3 517	5 317	3 385	3 372	3 461	3 445	3 477	3 494
34	System growth	2 841	3 262	3 877	3 839	4 174	4 337	5 988	2 568	3 113	2 918	2 395
35	Asset replacement and renewal	7 780	6 785	7 887	4 529	4 187	4 355	3 865	3 860	3 948	2 925	3 052
36	Asset relocations	17	-	-	-	-	-	-	-	-	-	-
37	Reliability, safety and environment:											
38	Quality of supply	125	1 297	1 329	1 225	869	486	159	478	283	76	642
39	Legislative and regulatory	-	119	117	-	-	-	-	-	-	-	-
40	Other reliability, safety and environment	397	630	1 082	1 348	1 333	1 110	542	556	554	559	562
41	**Total reliability, safety and environment**	522	2 046	2 527	2 573	2 202	1 596	701	1 034	837	635	1 204
42	**Expenditure on network assets**	14 874	18 651	18 249	14 458	15 881	13 673	13 926	10 923	11 343	9 955	10 144
43	Expenditure on non-network assets	824	778	331	716	764	652	635	635	635	1 199	635
44	**Expenditure on assets**	15 698	19 428	18 580	15 174	16 645	14 325	14 561	11 558	11 978	11 154	10 779
45												
46	**Subcomponents of expenditure on assets (where known)**											
	**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*											
47	Energy efficiency and demand side management, reduction of energy losses	-	-	-	-	539	-	-	-	-	564	-
48	Overhead to underground conversion	3 334	3 698	5 157	1 566	1 085	1 299	1 357	1 155	1 162	-	-
49	Research and development	-	-	-	-	-	-	-	-	-	-	-
51												

52		Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5	CY+6	CY+7	CY+8	CY+9	CY+10
53												
54	**Difference between nominal and constant price forecasts**	**$000**										
55	Consumer connection	(0)	-	150	225	459	366	439	529	606	693	780
56	System growth	-	-	147	246	360	468	780	392	547	582	535
57	Asset replacement and renewal	-	-	300	290	361	470	503	590	694	583	682
58	Asset relocations	(0)	-	-	-	-	-	-	-	-	-	-
59	Reliability, safety and environment:											

	Company Name	EA Networks (Electricity Ashburton Ltd)
	AMP Planning Period	1 April 2024 – 31 March 2034

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)
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sch ref												
60	Quality of supply	0	-	50	78	75	52	21	73	50	15	143
61	Legislative and regulatory	-	-	4	-	-	-	-	-	-	-	-
62	Other reliability, safety and environment	(0)	-	41	86	115	120	71	85	97	111	125
63	**Total reliability, safety and environment**	0	-	96	165	190	172	91	158	147	127	269
64	**Expenditure on network assets**	(0)	-	693	925	1 370	1 477	1 813	1 669	1 994	1 985	2 265
65	Expenditure on non-network assets	-	-	13	46	66	70	83	97	112	239	142
66	**Expenditure on assets**	(0)	-	706	971	1 436	1 547	1 896	1 766	2 106	2 224	2 407

67

68 **Commentary on options and considerations made in the assessment of forecast expenditure**

69 *EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast expenditure on assets for the current disclosure year and a 10 year planning period in Schedule 15*

70

71

72		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
73	**11a(ii): Consumer Connection**						
74	*Consumer types defined by EDB**	**$000 (in constant prices)**					
75	Urban LV	98	151	151	154	152	155
	Urban Transformer	83	82	82	84	83	84
	Urban Alteration for Safety (No new ICP created)	-	-	-	-	-	-
	Urban Capacity Alteration (No new ICP created)	4	24	24	25	24	25
	Rural LV	287	426	427	435	430	438
76	Rural Transformer	613	1 058	1 060	1 080	1 068	1 087
77	Rural Alteration for Safety (No new ICP created)	340	580	581	581	575	585
78	Rural Capacity Alteration (No new ICP created)	331	468	469	477	470	478
79	Other (including large subdivisions)	1 958	3 767	1 164	682	2 515	532
80	**include additional rows if needed*						
81	**Consumer connection expenditure**	3 714	6 557	3 958	3 517	5 317	3 385
82	*less* Capital contributions funding consumer connection	1 379	5 554	1 083	513	2 328	480
83	**Consumer connection less capital contributions**	2 335	1 003	2 875	3 004	2 989	2 905
84	**11a(iii): System Growth**						
85	Subtransmission	-	96	-	-	1 122	1 255
86	Zone substations	-	-	318	351	324	505
87	Distribution and LV lines	880	759	298	232	193	168
88	Distribution and LV cables	345	37	561	609	700	712
89	Distribution substations and transformers	1 115	1 954	2 136	2 033	1 625	1 507
90	Distribution switchgear	319	80	299	320	117	185
91	Other network assets	183	336	265	293	94	6
92	**System growth expenditure**	2 841	3 262	3 877	3 839	4 174	4 337
93	*less* Capital contributions funding system growth	-	-	-	-	-	-
94	**System growth less capital contributions**	2 841	3 262	3 877	3 839	4 174	4 337
95							

96		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
97							
98	**11a(iv): Asset Replacement and Renewal**	**$000 (in constant prices)**					
99	Subtransmission	-	-	-	197	506	515
100	Zone substations	279	365	105	102	74	75
101	Distribution and LV lines	792	1 961	1 928	2 118	1 827	1 693
102	Distribution and LV cables	690	3 326	4 640	1 316	1 043	1 240
103	Distribution substations and transformers	4 696	813	923	532	473	525
104	Distribution switchgear	1 089	321	291	264	264	208
105	Other network assets	235	-	-	-	-	99
106	**Asset replacement and renewal expenditure**	7 780	6 785	7 887	4 529	4 187	4 355
107	*less* Capital contributions funding asset replacement and renewal	-	-	-	-	-	-
108	**Asset replacement and renewal less capital contributions**	7 780	6 785	7 887	4 529	4 187	4 355
109							

Company Name	**EA Networks (Electricity Ashburton Ltd)**
AMP Planning Period	**1 April 2024 – 31 March 2034**

SCHEDULE 11a: REPORT ON FORECAST CAPITAL EXPENDITURE

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sch ref

11a(v): Asset Relocations

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
110								
111								
112	**11a(v): Asset Relocations**							
113		*Project or programme**	**$000 (in constant prices)**					
114		N/A	-	-	-	-	-	-
115		N/A	-	-	-	-	-	-
116		N/A	-	-	-	-	-	-
117		N/A	-	-	-	-	-	-
118		N/A	-	-	-	-	-	-
119		**include additional rows if needed*						
120		All other project or programmes - asset relocations	17	-	-	-	-	-
121		**Asset relocations expenditure**	17	-	-	-	-	-
122	*less*	Capital contributions funding asset relocations	-	-	-	-	-	-
123		**Asset relocations less capital contributions**	17	-	-	-	-	-
124								

11a(vi): Quality of Supply

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
125								
126								
127	**11a(vi): Quality of Supply**							
128		*Project or programme**	**$000 (in constant prices)**					
129		Security of Supply	30	-	-	-	-	-
		Replace on property poles	21	-	-	-	-	-
		Zone substation TX pad and protection	33	-	-	-	-	-
		11kV Core Network Centres	-	76	313	451	292	327
130		22kV Conversion - Methven Hwy Stage 1	-	152	-	-	-	-
131		22kV Surge Arrester - Replacement Programme	-	416	417	425	420	-
132		66kV OH Dampers Installation.	-	122	123	125	-	-
		UG New - Moorhouse Rd Fill In	-	254	-	-	-	-
		ZSS EGN - Ripple Injection Generator Replacement	-	-	159	66	-	-
		ZSS MSM - Mt Somers to Montalto 22 kV Feeder Protection	-	-	162	-	-	-
133		SCADA - Distribution Automation Programme	-	162	83	84	84	85
134		**include additional rows if needed*						
135		All other projects or programmes - quality of supply	41	113	72	74	73	74
136		**Quality of supply expenditure**	125	1 297	1 329	1 225	869	486
137	*less*	Capital contributions funding quality of supply	-	-	-	-	-	-
138		**Quality of supply less capital contributions**	125	1 297	1 329	1 225	869	486
139								

11a(vii): Legislative and Regulatory

sch ref			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5
140								
141								
142	**11a(vii): Legislative and Regulatory**							
143		*Project or programme**	**$000 (in constant prices)**					
144		Transpower Crossings - Improve Clearances	-	119	117	-	-	-
145		N/A	-	-	-	-	-	-
146		N/A	-	-	-	-	-	-
147		N/A	-	-	-	-	-	-
148		N/A	-	-	-	-	-	-
149		**include additional rows if needed*						
150		All other projects or programmes - legislative and regulatory	-					
151		**Legislative and regulatory expenditure**	-	119	117	-	-	-
152	*less*	Capital contributions funding legislative and regulatory	-	50	50	-	-	-
153		**Legislative and regulatory less capital contributions**	-	69	67	-	-	-
154								
155			Current Year CY	CY+1	CY+2	CY+3	CY+4	CY+5

Company Name	**EA Networks (Electricity Ashburton Ltd)**
AMP Planning Period	**1 April 2024 – 31 March 2034**

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)

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sch ref

156 11a(viii): Other Reliability, Safety and Environment

sch ref							
157	*Project or programme**	**$000 (in constant prices)**					
158	22kV OH Rebuild - Transformer Pole Replacements	-	482	966	1 230	1 217	991
159	DSS - Earthing Upgrades	266	53	53	54	54	55
160	ZSS - Substation Surveillance Programme	-	32	-	-	-	-
161	SCADA Control Box Installation	115	-	-	-	-	-
162	N/A	-	-	-	-	-	-
163	**include additional rows if needed*						
164	All other projects or programmes - other reliability, safety and environment	16	63	63	64	63	64
165	**Other reliability, safety and environment expenditure**	397	630	1 082	1 348	1 333	1 110
166	*less* Capital contributions funding other reliability, safety and environment	-	-	-	-	-	-
167	**Other reliability, safety and environment less capital contributions**	397	630	1 082	1 348	1 333	1 110
168							
169		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
170							

171 11a(ix): Non-Network Assets

sch ref							
172	**Routine expenditure**						
173	*Project or programme**	**$000 (in constant prices)**					
174	Routine Vehicles	-	124	99	75	75	75
175	Routine Plant	-	10	10	10	10	10
176	Routine Info Tech	74	560	86	531	40	517
177	Routine Building Work	3	50	100	100	100	50
178	N/A	-	-	-	-	-	-
179	**include additional rows if needed*						
180	All other projects or programmes - routine expenditure	165	-	-	-	-	-
181	**Routine expenditure**	242	744	295	716	225	652
182	**Atypical expenditure**						
183	*Project or programme**						
184	Bunker Fire Suppression System	107	-	-	-	-	-
	Gawler Downs Communications Pole	256	-	-	-	-	-
	CAT Generator Control	69	-	-	-	-	-
	SFRA Test Set for Power Transformers	-	34	-	-	-	-
185	Industrial Acoustic Imaging Camera	-	-	36	-	-	-
186	ADMS Basic DERMS	-	-	-	-	539	-
187	Main Office Solar	150	-	-	-	-	-
188	N/A	-	-	-	-	-	-
189	**include additional rows if needed*						
190	All other projects or programmes - atypical expenditure	-	-	-	-	-	-
191	**Atypical expenditure**	582	34	36	-	539	-
192							
193	**Expenditure on non-network assets**	824	778	331	716	764	652
194							

Schedule 11b Report on Forecast Operational Expenditure

Company Name	**EA Networks (Electricity Ashburton Ltd)**
AMP Planning Period	**1 April 2024 – 31 March 2034**

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). EDBs must express the information in this schedule (11b) as a specific value rather than ranges. If EDBs wish to provide any supporting information about these values, this may be disclosed in Schedule 15 (Voluntary 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
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												
9	**Operational Expenditure Forecast**	**$000 (in nominal dollars)**										
10	Service interruptions and emergencies	728	861	894	916	936	954	973	993	1013	1033	1054
11	Vegetation management	725	1045	1084	1111	1135	1157	1181	1204	1228	1253	1278
12	Routine and corrective maintenance and inspection	958	1611	1624	1696	1700	1734	1769	1804	1840	1877	1915
13	Asset replacement and renewal	1004	1565	1710	1641	1693	1687	1683	1629	1663	1697	1731
14	**Network Opex**	3415	5082	5312	5365	5463	5533	5606	5631	5744	5861	5977
15	System operations and network support	5731	7006	6320	7744	6947	7074	7230	7366	8457	7744	7905
16	Business support	7816	9081	8721	8701	8884	8763	8939	9117	9299	9486	9675
17	**Non-network opex**	13547	16087	15041	16445	15831	15837	16168	16483	17756	17230	17580
18	**Operational expenditure**	16962	21169	20354	21811	21294	21370	21774	22114	23500	23091	23558
19		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
20												
21		**$000 (in constant prices)**										
22	Service interruptions and emergencies	728	861	861	861	861	861	861	861	861	861	861
23	Vegetation management	725	1045	1045	1045	1045	1045	1045	1045	1045	1045	1045
24	Routine and corrective maintenance and inspection	958	1611	1565	1594	1565	1565	1565	1565	1565	1565	1565
25	Asset replacement and renewal	1004	1565	1647	1542	1559	1523	1489	1413	1414	1415	1415
26	**Network Opex**	3415	5082	5118	5042	5029	4994	4960	4885	4886	4886	4886
27	System operations and network support	5731	7006	6089	7278	6395	6384	6397	6389	7192	6457	6462
28	Business support	7816	9081	8402	8178	8178	7909	7909	7909	7909	7909	7909
29	**Non-network opex**	13547	16087	14491	15456	14573	14293	14306	14298	15101	14366	14371
30	**Operational expenditure**	16962	21169	19608	20499	19603	19287	19266	19183	19987	19252	19257
31	**Subcomponents of operational expenditure (where known)**											
	**EDBs' must disclose both a public version of this Schedule (excluding cybersecurity cost data) and a confidential version of this Schedule (including cybersecurity costs)*											
32	Energy efficiency and demand side management, reduction of											
33	energy losses	-	-	-	-	80	80	80	80	80	160	160
34	Direct billing*	-	-	-	-	-	-	-	-	-	-	-
35	Research and Development	-	-	-	-	-	-	-	-	-	-	-
36	Insurance	394	377	377	377	377	377	377	377	377	377	377
38	** Direct billing expenditure by suppliers that direct bill the majority of their consumers*											
39												
40		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*	*CY+6*	*CY+7*	*CY+8*	*CY+9*	*CY+10*
41												
42	**Difference between nominal and real forecasts**	**$000**										
43	Service interruptions and emergencies	-	-	33	55	74	93	112	132	151	172	192
44	Vegetation management	-	-	40	67	90	113	136	160	184	208	233
45	Routine and corrective maintenance and inspection	-	-	59	102	135	169	204	239	275	312	350
46	Asset replacement and renewal	-	-	63	99	135	164	194	216	249	282	316
47	**Network Opex**	-	-	194	323	434	539	646	746	859	974	1091
48	System operations and network support	-	-	231	466	552	690	833	976	1264	1288	1443
49	Business support	-	-	319	523	706	854	1030	1208	1390	1577	1766
50	**Non-network opex**	-	-	551	989	1258	1544	1863	2185	2655	2865	3209
51	**Operational expenditure**	-	-	745	1312	1692	2083	2508	2931	3514	3839	4300
52												
53	**Commentary on options and considerations made in the assessment of forecast expenditure**											
54	*EDBs may provide explanatory comment on the options they have considered (including scenarios used) in assessing forecast operational expenditure for the current disclosure year and a 10 year planning period in Schedule 15.*											
55												

Schedule 12a Report on Asset Condition

Company Name: **EA Networks (Electricity Ashburton Ltd)**

AMP Planning Period: **1 April 2024 – 31 March 2034**

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	H1	H2	H3	H4	H5	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)							
8												
9												
10	All	Overhead Line	Concrete poles / steel structure	No.	-	0.35%	0.70%	78.89%	20.06%	-	2	0.09%
11	All	Overhead Line	Wood poles	No.	1.09%	1.77%	12.67%	42.63%	41.84%	-	2	1.53%
12	All	Overhead Line	Other pole types	No.	-	-	20.00%	40.00%	40.00%	-	2	-
13	HV	Subtransmission Line	Subtransmission OH up to 66kV conductor	km	-	0.23%	4.50%	62.00%	33.27%	-	3	0.06%
14	HV	Subtransmission Line	Subtransmission OH 110kV+ conductor	km							N/A	
15	HV	Subtransmission Cable	Subtransmission UG up to 66kV (XLPE)	km	-	-	2.23%	51.18%	46.59%	-	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.	-	-	27.27%	40.91%	31.82%	-	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.	-	22.22%	77.78%	-	-	-	3	5.56%
28	HV	Zone substation switchgear	33kV Switch (Ground Mounted)	No.							N/A	
29	HV	Zone substation switchgear	66/33kV Switch (Pole Mounted)	No.	-	1.92%	30.77%	42.31%	25.00%	-	3	0.48%
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.	-	-	37.50%	36.11%	26.39%	-	3	-
33	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (ground mounted)	No.	-	1.06%	8.47%	40.74%	49.74%	-	2	0.26%
34	HV	Zone substation switchgear	3.3/6.6/11/22kV CB (pole mounted)	No.							N/A	
35												

Company Name	**EA Networks (Electricity Ashburton Ltd)**
AMP Planning Period	**1 April 2024 – 31 March 2034**

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												
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.	3.23%	3.23%	12.90%	48.39%	32.26%	-	3	-
40	HV	Distribution Line	Distribution OH Open Wire Conductor	km	1.16%	3.26%	17.80%	47.40%	30.39%	-	3	1.97%
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%	2.65%	24.23%	73.10%	-	3	0.01%
44	HV	Distribution Cable	Distribution UG PILC	km	7.42%	-	78.75%	13.82%	-	-	1	1.86%
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.	-	-	14.29%	75.00%	10.71%	-	2	-
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.	-	0.78%	4.84%	45.73%	48.65%	-	2	0.19%
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.	6.35%	7.99%	13.61%	32.30%	39.75%	-	3	1.59%
51	HV	Distribution Transformer	Pole Mounted Transformer	No.	0.47%	5.52%	19.76%	35.41%	38.84%	-	3	0.47%
52	HV	Distribution Transformer	Ground Mounted Transformer	No.	0.27%	6.57%	16.00%	21.63%	55.54%	-	3	0.27%
53	HV	Distribution Transformer	Voltage regulators	No.	-	7.69%	7.69%	53.85%	30.77%	-	3	-
54	HV	Distribution Substations	Ground Mounted Substation Housing	No.	4.00%	3.65%	11.83%	24.00%	56.52%	-	2	4.91%
55	LV	LV Line	LV OH Conductor	km	7.99%	12.08%	14.42%	57.11%	8.40%	-	3	11.01%
56	LV	LV Cable	LV UG Cable	km	0.02%	1.29%	10.48%	32.09%	56.12%	-	3	0.34%
57	LV	LV Streetlighting	LV OH/UG Streetlight circuit	km	0.67%	2.21%	10.22%	35.52%	51.38%	-	2	2.88%
58	LV	Connections	OH/UG consumer service connections	No.	-	-	-	4.50%	34.20%	61.30%	3	-
59	All	Protection	Protection relays (electromechanical, solid state and numeric)	No.	-	2.21%	1.84%	1.47%	94.49%	-	2	2.21%
60	All	SCADA and communications	SCADA and communications equipment operating as a single system	Lot	-	-	-	10.00%	90.00%	-	3	-
61	All	Capacitor Banks	Capacitors including controls	No.							N/A	
62	All	Load Control	Centralised plant	Lot	-	70.00%	30.00%	-	-	-	3	70.00%
63	All	Load Control	Relays	No.	-	-	-	-	-	100.00%	1	-
64	All	Civils	Cable Tunnels	km							N/A	

Schedule 12b Report on Forecast Capacity

Company Name	EA Networks (Electricity Ashburton Ltd)
AMP Planning Period	1 April 2024 – 31 March 2034

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 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 future fast transfer switched capacity (Core network) will 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 uses surrounding 22kV network.
11	Coldstream 66/22kV [CSM]	13	-	N	9	-	-	-	Transformer	Second Carew transformer provides an increase in transfer capacity. Transfer capacity uses surrounding 22kV network.
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 66/22kV [EFN]	9	-	N	4	-	-	-	Transformer	Now operating at 66/22 kV and all load able to be back-fed. Transfer capacity uses surrounding 22kV network.
14	Elgin 66/22kV [EGN]	3	-	N-1 Switched	7	-	-	-	Transformer	Existing 66/33/22kV 20MVA transformer. Partly unloads some 66kV circuits and provides secure back-feeds at 22kV to other sites. Load is 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	Recent 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 along with surrounding 22kV network provides transfer capacity. 66/22kV MSM also significantly increased transfer capacity.
17	Highbank 66/11kV [HBK]	8	-	N	-	-	-	-	Subtransmission circuit	Owned by Manawa Energy. 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	-	20	-	Transformer	Transfer capacity uses 22kV from OVD, FTN, & MTV, larger OVD transformer, and increased MTV 22kV supply capability. Second 66/22kV transformer (35MVA) to be added. Future peak demand (50 MVA) will be caused by generation.
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 2024. Will be decommissioned after 2024.
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 provide 100% transfer capacity.
22	Methven 66/33kV [MTV]	5	-	N	5	-	-	-	No constraint within +5 years	Most 33kV load beyond MTV being converted to 66/22kV. Remaining 33kV load is supplied by stepping up 22/33 kV.
23	Mt Somers 66/22kV [MSM]	3	5	N-1 Switched	3	58%	-	-	Transformer	Conversion to 66/22kV plus further conversion of surrounding distribution network to 22kV permits adequate switched transfer capacity. Additional 66kV circuit in 2024 will provide N-1 subtransmission security (currently N subtransmission security). Future peak demand (17 MVA) will be caused by generation.
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 significantly increase switched transfer capacity and other work an alternative route.
25	Montalto 33/11kV [MON]	2	-	N	1	-	-	-	Transformer	Conversion to 22kV distribution network increases transfer capacity in 2025-26. Decommissioned as 22kV conversion proceeds.
26	Northtown 66/11kV [NTN]	14	22	N-1	20	64%	20	80%	No constraint within +5 years	Currently no subtransmission network constraint. Additional 11kV cables in Ashburton (Core network) increase fast transfer capacity from ASH.
27	Overdale 66/22kV [OVD]	14	-	N	10	-	-	-	Transformer	Transfer capacity has increased with larger 66/22kV transformers at adjacent substations ([PDS] & [LSN]), additional 22kV conversion, and Fairton 66/22kV construction.
28	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. Second transformer is one of two system spares.
29	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 using 22 kV network).
30	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 adjacent 22/11kV and 66/11kV substations.
31	Wakanui 66/22kV [WNU]	13	-	N	10	-	-	-	Transformer	Elgin's 66/33/22kV transformer provides 22kV fast transfer capacity.

32 [1] *Extend forecast capacity table as necessary to disclose all capacity by each zone substation*

Schedule 12c Report on Forecast Network Demand

Company Name	**EA Networks (Electricity Ashburton Ltd)**
AMP Planning Period	**1 April 2024 – 31 March 2034**

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

sch ref							
7	**12c(i): Consumer Connections**						
8	*Number of ICPs connected during year by consumer type*				**Number of connections**		
9		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
10							
11	*Consumer types defined by EDB**						
12	Urban LV	62	55	50	45	45	45
	Urban Transformer	1	5	5	5	5	5
	Urban Alteration for Safety (No new ICP created)	-	-	-	-	-	-
	Urban Capacity Alteration (No new ICP created)	1	5	5	5	5	5
	Rural LV	41	50	50	45	45	45
13	Rural Transformer	34	40	40	40	40	40
14	Rural Alteration for Safety (No new ICP created)	14	20	15	15	15	15
15	Rural Capacity Alteration (No new ICP created)	12	15	15	15	15	15
16	Other	159	100	80	60	60	60
17	**Connections total**	324	290	260	230	230	230
18	**include additional rows if needed*						
19							
20							
21							
22	**Distributed generation**	*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
23	Number of connections made in year	110	120	130	130	140	140
24	Capacity of distributed generation installed in year (MVA)	1	58	17	10	33	3
25	**12c(ii) System Demand**						
26		*Current Year CY*	*CY+1*	*CY+2*	*CY+3*	*CY+4*	*CY+5*
27	**Maximum coincident system demand (MW)**						
28	GXP demand	171	173	175	177	179	181
29	*plus* Distributed generation output at HV and above	1	10	13	13	19	19
30	**Maximum coincident system demand**	172	183	188	190	198	200
31	*less* Net transfers to (from) other EDBs at HV and above	-	-	-	-	-	-
32	**Demand on system for supply to consumers' connection points**	172	183	188	190	198	200
33	**Electricity volumes carried (GWh)**						
34	Electricity supplied from GXPs	507	478	372	364	316	321
35	*less* Electricity exports to GXPs	-	-	-	6	16	17
36	*plus* Electricity supplied from distributed generation	139	173	284	305	368	370
37	*less* Net electricity supplied to (from) other EDBs	-	-	-	-	-	-
38	**Electricity entering system for supply to ICPs**	646	651	656	663	669	674
39	*less* Total energy delivered to ICPs	608	613	618	623	628	633
40	**Losses**	38	38	38	40	41	41
41							
42	**Load factor**	43%	41%	40%	40%	39%	38%
43	**Loss ratio**	5.9%	5.8%	5.9%	6.0%	6.1%	6.1%
44							

Schedule 12d Report on Forecast Interruptions and Duration

Company Name	**EA Networks (Electricity Ashburton Ltd)**
AMP Planning Period	**1 April 2024 – 31 March 2034**
Network / Sub-network Name	**EA Networks (Electricity Ashburton Ltd)**

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							
10	**SAIDI**						
11	Class B (planned interruptions on the network)	117.5	275.0	275.0	275.0	275.0	275.0
12	Class C (unplanned interruptions on the network)	53.5	92.0	92.0	92.0	92.0	92.0
13	**SAIFI**						
14	Class B (planned interruptions on the network)	0.42	0.98	0.98	0.98	0.98	0.98
15	Class C (unplanned interruptions on the network)	0.96	1.29	1.29	1.29	1.29	1.29

Schedule 14a Mandatory Explanatory Notes on Forecast Information

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.

   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)

2. 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 2024-25 year. Costs have been prepared using 2024-25 values for labour, plant and materials. Years after 2024-25 have been escalated by the "Fiscal Strategy Model - PREFU 2023" CPI Forecast by the New Zealand Government Treasury published in September 2023. When the forecast ends, the final year CPI value has been used until the period end.

(https://www.treasury.govt.nz/publications/fsm/fiscal-strategy-model-prefu-2023)

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

3. 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 2024-25 year. Costs have been prepared using 2024-25 values for labour, plant and materials. Years after 2024-25 have been escalated by the "Fiscal Strategy Model - PREFU 2023" CPI Forecast by the New Zealand Government Treasury published in September 2023. When the forecast ends, the final year CPI value has been used until the period end.

(https://www.treasury.govt.nz/publications/fsm/fiscal-strategy-model-prefu-2023)

Financial Year (ending March)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Treasury CPI Forecast (%)	3.8	2.5	2.1	2.0	2.0	2.0	2.0	2.0	2.0	N/A
Cumulative CPI Price Inflator	1.0000	1.0380	1.0640	1.0863	1.1080	1.1302	1.1528	1.1758	1.1994	1.2233

Schedule 17 Certification for Year-beginning Disclosures

Schedule 17 Certification for Year-beginning Disclosures

Clause 2.9.1

We, **Andrew David Barlass** and **Paul Jason Munro**, being directors of **Electricity Ashburton Ltd** 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 2.4.1, 2.6.1, 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.

Andrew David Barlass	Paul Jason Munro
5 March 2024	5 March 2024

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