September 2022

Appendices: Regulatory Matters for our Draft Plan

for consultation

Empowering communities for a resilient, affordable and net-zero future.

Ausgrid

List of appendices

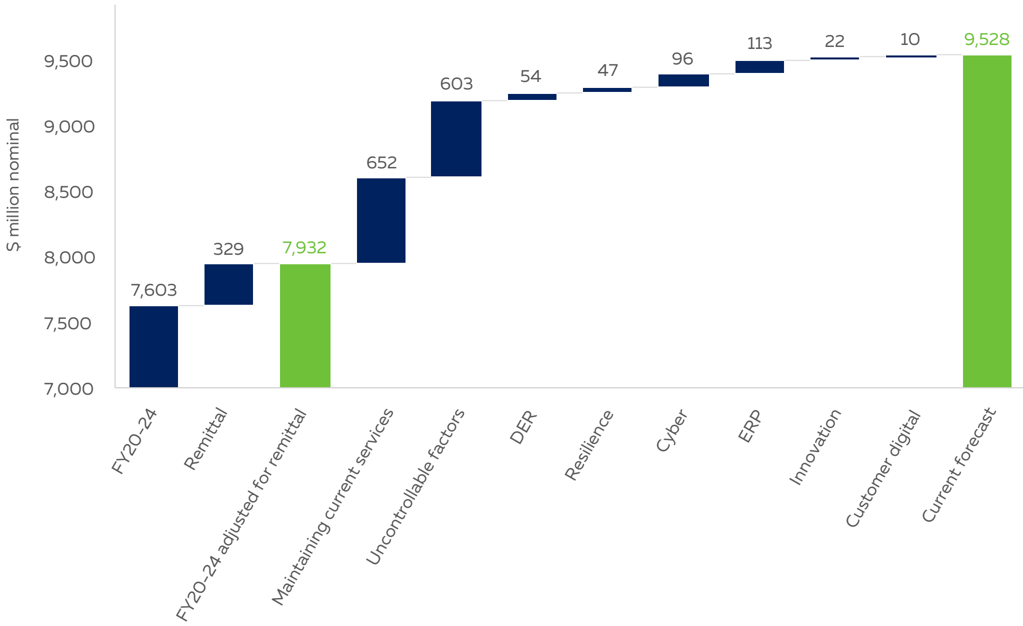
Introduction

The following appendices outline the technical regulatory details of our **Draft Plan**. This includes how we have converted the potential initiatives and investments outlined in **Section 4** of the Draft Plan into our forecast revenue and indicative bill outcomes.

As discussed in **Section 5** of the Draft Plan, the revenue we would require to recover the costs of the potential new investments is only a small portion of the overall bill increases.

Figure 1 shows the forecast revenue that results from the Draft Plan, broken down by factors primarily within and outside our control. Most of the increase is driven by factors that are challenging for us to control.

Figure 1: Forecast building block revenue ($ million, nominal)



Notes:

1. Ausgrid revenue, not total NUOS.
2. 'Remittal' is the amount paid back in 2019-24 for revenue over-recovery in 2014-19. Adding this back to 2019-24 revenue allows comparison of like with like revenue.
3. Maintaining current services is predominantly return on asset and depreciation of business as usual capex and assumes:
   - Capex in 2024-29 excludes amounts itemised in other steps;
   - Opex is rolled forward with no step changes;
   - Actual inflation equals forecast inflation in the current period; and
   - Weighted average cost of capital (**WACC**) is the same as current period.
4. 'Uncontrollable factors' include WACC, actual inflation, insurance and software accounting changes. Itemised revenue impacts are based on total expenditure (opex plus capex).

The appendices are as follows:

- **Appendix A** details our current thinking on capex;
- **Appendix B** details our current thinking on opex;
- **Appendix C** provides more detail about overall revenue; and
- **Appendices D-G** provide further regulatory information that may assist in understanding key aspects we are considering for our regulatory proposal in January 2023. This includes demand forecasts, cost pass throughs and service classification.

A 2024-29 capital expenditure

Capex is a significant driver of our component of electricity prices and customer bills. It refers to the investments we make in network assets (e.g. poles and wires) and supporting non-network assets (e.g. ICT systems, property and motor vehicles) to deliver customers the service they expect from us.

The assets we invest in today can remain in service beyond 2070. Throughout the life of these assets, we receive income to compensate for the cost of raising finance for these assets and to recover the value of the investment. In this way, the cost of an asset built today is not just borne by current customers but also future generations that may use the asset over its useful life.

Total forecast capex

Our total forecast capex for 2024-29 is $3,239 million. This is 7% higher than our current period spend.[1] Though an increase, this amount of capex will not cause growth in the value of our RAB per customer in real terms. This is because the amount of capex we forecast adding to the RAB is similar, in real terms, to the amount scheduled to be subtracted through depreciation, while our customer numbers are increasing.

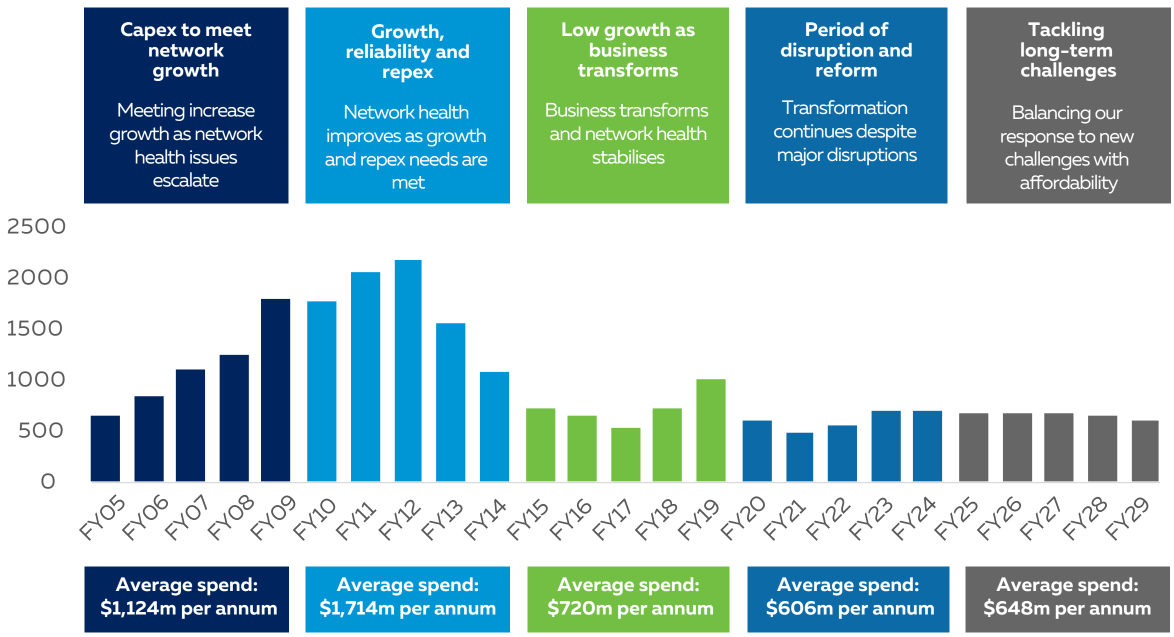
We are consulting on whether our approach appropriately balances the need to maintain the affordability of our services with the need to tackle long-term challenges like climate change, the facilitation of a net zero future and keeping pace with cyber threats.

Rising to the challenges ahead

We have experienced a period of major disruptions in recent years, including the COVID-19 pandemic, industrial action, and a pause on live work on our network. These disruptions slowed our capital program in the early years of the 2019-24 period, as shown in **Figure A.1**. During this period, we also took steps to transform our business by lowering our cost footprint and implementing reforms to make us more productive.

The reforms we introduced have set us up to meet the challenges that lie ahead. They will allow us to keep our 2024-29 capex reflective of our spend in recent years while we tackle the challenges of the future.

Figure A.1: We will keep our capex levels over the 2024-29 period consistent with recent periods ($ million, real FY24)



1 Our 2024-29 capex is 11% higher than the current period if Software-as-a-Service (**SaaS**) costs, which are now opex, were treated as capex.

Our self-assessment of our current forecast

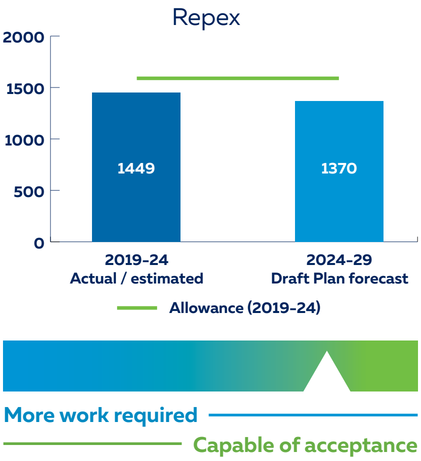
Our aim is to submit a regulatory proposal to the AER that is 'capable of acceptance'. We want to hear from our customers about how close they think we are to meeting this standard.

Figures A.2 and **A.3** below include a self-assessment which we invite stakeholders to review and, where they disagree, challenge. To perform this self-assessment, we have considered our forecast relative to our current period spend and other key considerations like the engagement we have had to date with our customers.

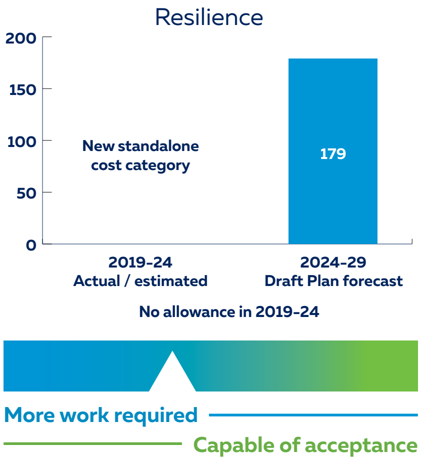
The feedback we get will help us focus our attention on the key areas that require more work, giving us the best chance to lodge a regulatory proposal that is capable of acceptance by the AER.

Consultation question 11:
What parts of our self-assessment do you agree or disagree with and why?

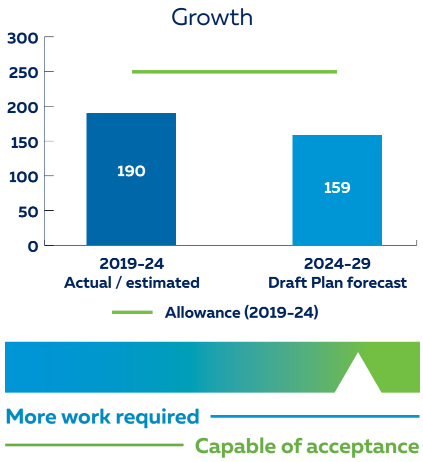
Figure A.2 Network and overheads capex ($ million, real FY24)



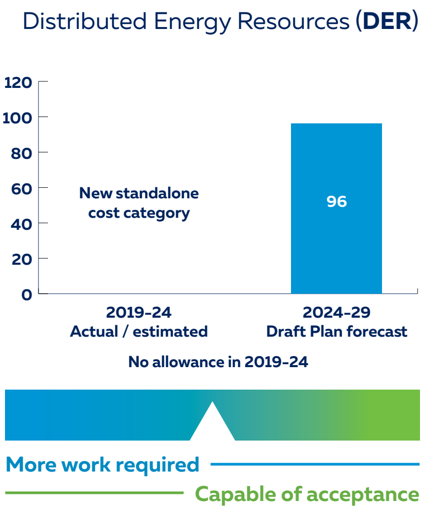
Our repex forcast is 5% below our 2019-24 spend and 14% below our 2019-24 allowance



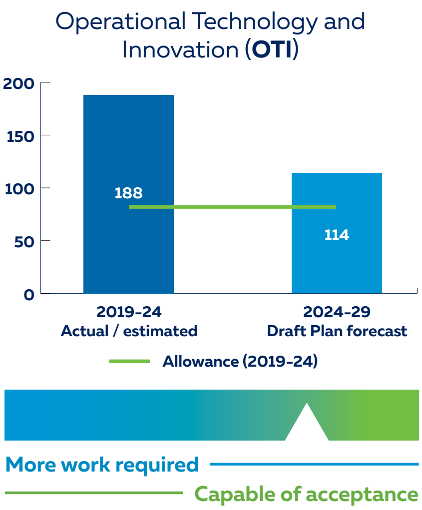
We are in the process of applying our Resilience Framework in collaboration with customer advocates



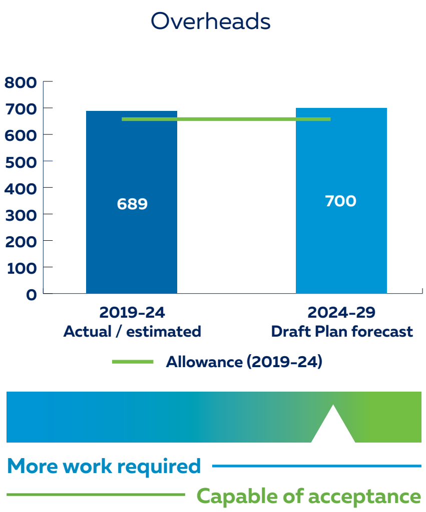
Our growth forecast is 16% below our 2019-24 spend and 35% below our 2019-24 allowance



We are finalising key inputs into our DER enablement program

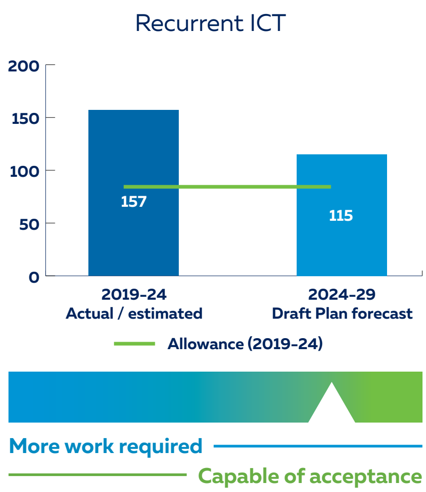


Our OTI forecast is 39% below our 2019-24 spend

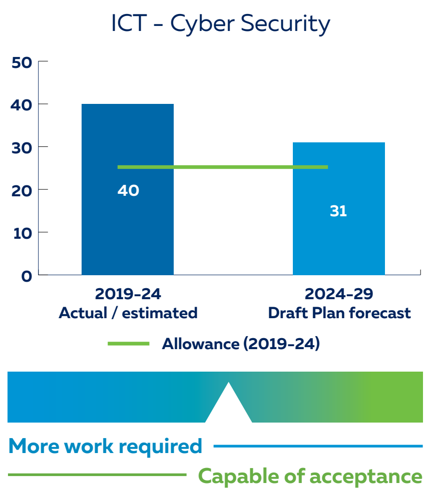


We have used the AER's standard 75:25 fixed-to-variable approach to test the efficiency of our overheads

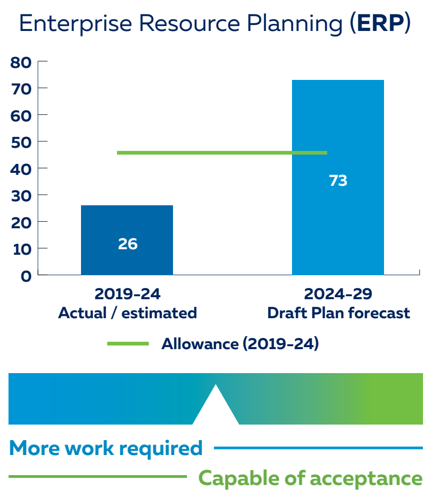
Figure A.3 Non-network capex ($ million, real FY24)



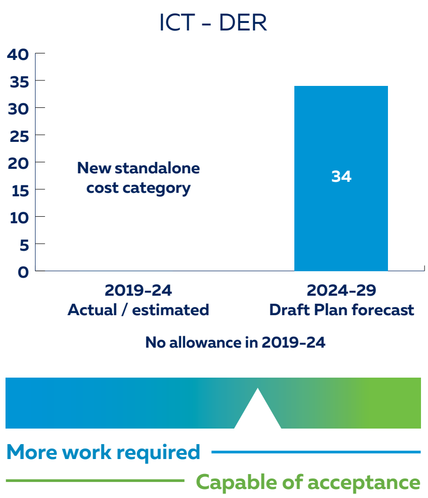
Our total recurrent ICT spend in 2024-29 is $115 m capex and $29 m SaaS opex. The capex component is 27% less than our 2019-24 spend and at the total expenditure level, including SaaS, 8% lower



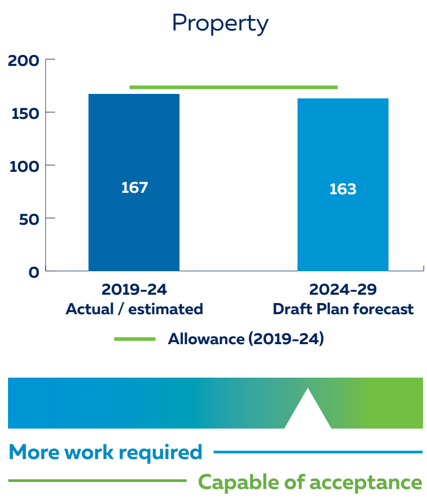
Our total cyber spend in 2024-29 is $31 m capex and $57 m SaaS opex. The capex component is 23% less than our 2019-24 spend. At the total expenditure level, including SaaS, it is 118% more



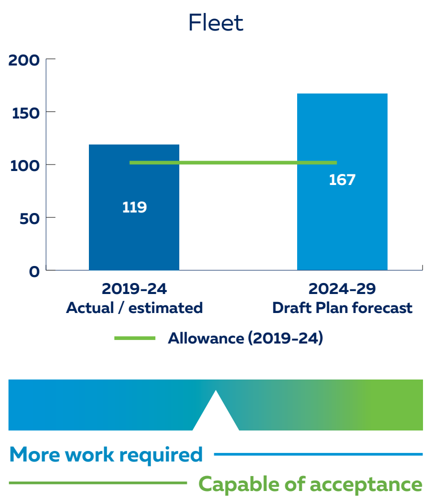
The total cost of our ERP replacement program is $143 m ($73 m in capex and $70 m in SaaS opex)



Our DER-related ICT program will provide the network visibility we need to enable our customers' DER ambitions



Our property forecast is in line with our 2019-24 spend and allowance



Our fleet forecast is 41% higher than our 2019-24 spend due to our elevated work platform (**EWP**) replacement program and changes to safety standards

Note 1: SaaS implementation costs are treated as capex in the 2019-24 period but, following an accounting standards change, will be treated as capex in the 2024-29 period.

Total forecast capex by investment driver

Figure A.4 shows the contribution of the different categories or drivers of capex to our total forecast capex of $3,239 million for 2024-29. This appendix discusses our forecasts for each of these investment drivers in turn.

Figure A.4 Capex forecast by driver ($ million, real FY24)

	FY25	FY26	FY27	FY28	FY29	FY20-24 actual/ estimated	FY25-29 total forecast	% change
Replacement	278	258	265	300	271	1,449	1,370	-5%
Resilience	24	37	45	39	34	1	179	n/a
Growth	43	30	29	29	29	190	159	-16%
DER	14	17	21	21	22	4	96	n/a
OTI	29	21	20	23	22	188	114	-39%
ICT	66	96	56	37	36	222	292	32%
Fleet	44	41	32	25	26	119	167	41%
Property	36	24	53	23	27	167	163	-2%
Overheads	137	139	143	141	139	689	700	1%
Total	**671**	**663**	**663**	**638**	**605**	**3,030**	**3,239**	**7%**

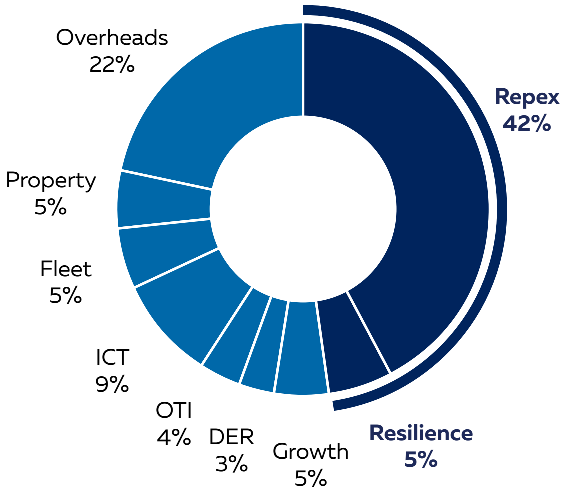
Note: Excludes SaaS costs in 2024-29 which were treated as capex in the 2019-24 period.

Replacement (repex) and climate resilience capex

Our current forecast repex for 2024-29 is $1,370 million. This is our largest capex category, representing 42% of our total forecast capex program in the 2024-29 period.

Our resilience program is $179 million. Of this, $66 million is currently repex in nature (**resilience repex**) and up to $113 million relates to network growth, piloting innovative solutions, and co-funding projects with councils. We plan to refine our resilience program over the coming months when we 'road test' our Resilience Framework with the RCP.

Figure A.5 Forecast repex and climate resilience expenditure as a percentage of total capex



What does repex mean for our customers?

Repex involves replacing assets at the end of their life. This can be triggered by:

- A failure of an asset;
- An assessment of asset condition; or
- Risk analysis that identifies replacement as the least-cost option after considering factors such as reliability, safety and maintenance costs.

For our customers, repex is key to ensuring the safety of our assets embedded within our communities and to maintain our current level of network reliability and performance.

What we have heard so far

Customers are telling us to maintain existing levels of reliability, build climate resilience, and promote affordability at a time of rising cost of living pressures.

This is a difficult balancing act. The more we invest in replacing assets or building resilience, the higher customer bills. At the same time, not enough investment can trigger a decline in the health of our network, putting safety, reliability, and long-term affordability at risk if we need to catch up on a large amount of deferred investment in a short timeframe.

Equity is another factor important to customers. They feel it is unfair for customers in some locations to experience materially worse levels of reliability than others due to climate change. Building resilience for these customers is among the key recommendations of the Voice of Community Panel.

What we are considering

We are considering how we can optimise our replacement requirements without compromising the health of our network and, above all else, the safety of the communities we serve.

Striking the right balance requires sophisticated economic tools that use engineering data about our network. The main tool we use is Cost Benefit Analysis (**CBA**), which we recently refreshed in response to the AER's feedback at our last regulatory reset.

CBA approach

Our refreshed CBA approach is much more sophisticated than the tools we used for our 2019-24 proposal. It enables us to run individual CBA calculations for discrete assets like switchgear, transformers and poles using data on past performance (e.g. failure rates). We can model the underlying risks and customer value (benefit) of millions of assets. To our knowledge, no other network in Australia can do this at the same scale and level of sophistication.

Our 2024-29 repex forecast is 5% lower than our current period spend and 14% below our 2019-24 allowance. We consider this to be a 'proof point' that we are taking our customers' concerns about affordability seriously. It is also a reduction in investment that our refreshed CBA approach allows us to make. This is by giving us the sophisticated tools needed to optimise the balance between the cost of replacement and other considerations such as safety and reliability. We will continue to review our replacement needs based on our network's health and our program delivery ahead of our January 2023 regulatory proposal.

Incorporating resilience expenditure efficiently

A large share of our forecast resilience expenditure involves replacing existing assets.

As **Figure A.6** shows, when the relevant component of resilience is included in repex, our total repex over 2024-29 is reflective of our repex in the 2019-24 period.

We have heard from our customers that they want us to tackle long-term challenges like climate change while still promoting affordability. We have responded to this by keeping our repex costs stable, even after incorporating new resilience initiatives.

We are also looking into how we can promote an equitable distribution of benefits from our resilience program.

This may involve building resilience in more remote communities on our network so that their level of reliability does not materially fall below what our other customers, on average, experience.

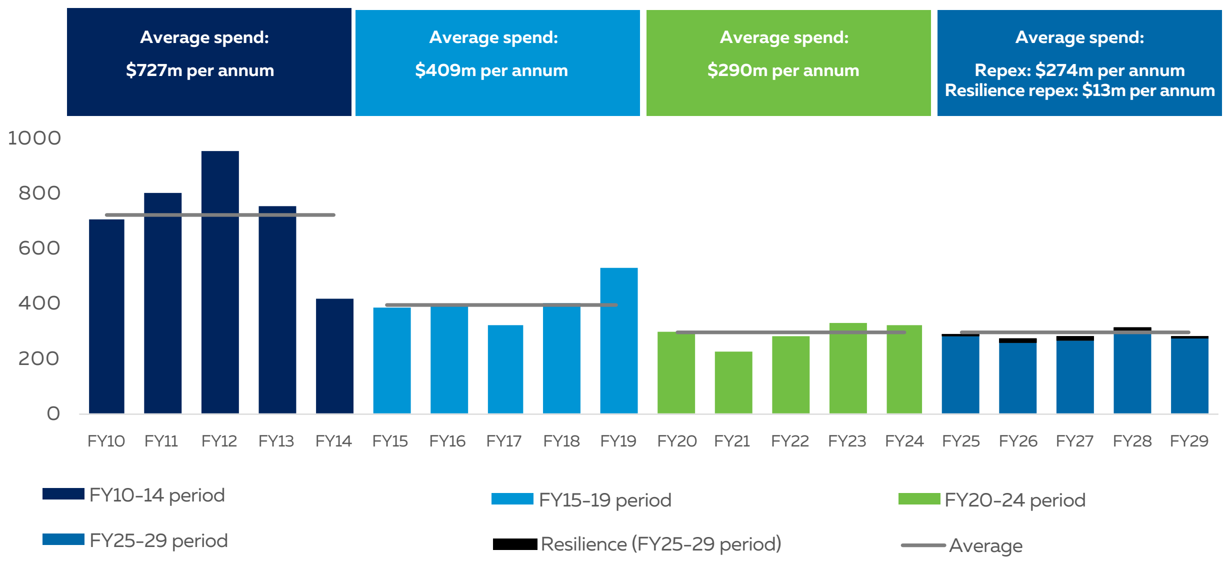
We expect the incorporation of equity into our investment decision making to be a topic of ongoing engagement with our customers.

The initiatives that we settle on will be driven by our co-designed Climate Resilience Framework which we have published for consultation with our Draft Plan.

Climate Resilience Framework

We have co-designed a Climate Resilience Framework with the RCP (see **Section 4.1** of our Draft Plan). Over the coming months we will use the Climate Resilience Framework to settle on resilience initiatives that will inform our 2024-29 regulatory submission due in January 2023.

Figure A.6 Our forecast repex and resilience expenditure for 2024-29 is in line with our actual/estimated expenditure in the current period ($ million, real FY24)



Our forecast repex compares well with the AER's repex model

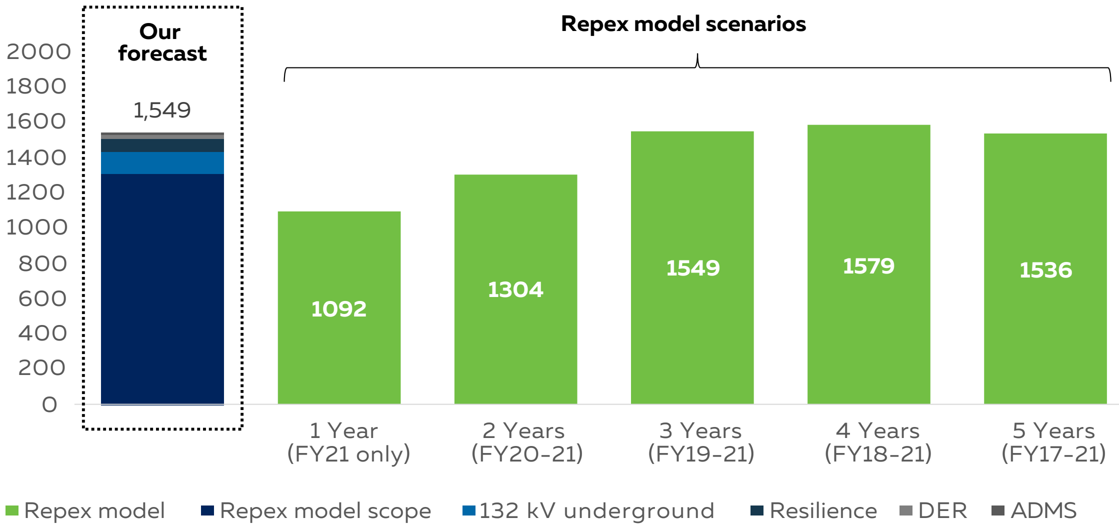
The AER has developed a repex evaluation model (**repex model**) which considers the age, cost and life of assets both at an individual electricity distributor level and an industry benchmark. We use the AER's repex model as a top-down check of the reasonableness of our forecast repex.

The repex model can be run over multiple scenarios that vary depending on how many years of data is taken into account. Under the repex model, lower levels of delivery are trended forward.

This can cause issues when transient factors such as COVID-19, a live work pause or industrial action slow replacement activity, as they did to varying degrees in FY20, FY21 and FY22.

Figure A.7 below compares our forecast repex (including repex-related resilience) against the AER's repex model. It shows that when at least 3 years of data (FY19-21) is considered, our forecast performs in line with what the repex model would expect, even when factoring in our climate resilience program.

Figure A.7 Forecast repex and resilience expenditure for the 2024-29 period compared with the AER's repex model scenarios ($ million, real FY24)



Source: Ausgrid analysis using Regulatory Information Notice data and the AER's repex model

The repex model uses statistical analysis and industry-wide benchmarking to test, at a high level, if our 2024-29 forecast is efficient.

The repex model also passes on all productivity efficiencies to customers by setting our allowance on the lower of our actual unit costs and the NEM benchmark.

Unit rates approach

We forecast 'unit rates' to inform our 10-year investment plan and CBA methodology. These comprise:

- Labour;
- Material components; and
- Contract services.

The labour component feeds into our workforce plan. The workforce plan sets out the different skillsets required to efficiently deliver our network capital and maintenance programs, while managing resourcing constraints that can add to our costs.

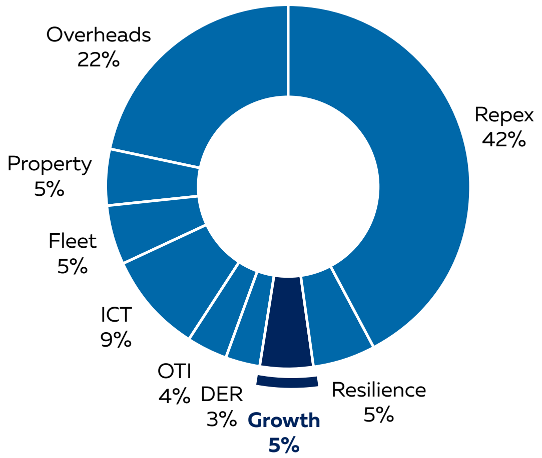
Our unit costs are currently facing upward pressures, including from modern safety controls which are necessary to protect our staff and the broader community, and from increases in the cost of materials (wooden poles, steel etc).

Despite these cost pressures, we have sought to promote affordability by putting forward a 2024-29 repex forecast that is reflective of our expenditure in recent years.

Growth capex

Our current forecast growth for the 2024-29 period is $159 million. This represents 5% of our total capex program.

Figure A.8 Forecast growth as a percentage of total forecast capex



What does growth capex mean for our customers?

Growth capex includes investments in customer connections and network augmentation. These activities enable new customers to connect to our network and the network to meet its predicted load growth. This keeps our power supply safe, reliable and secure.

Some parts of our network are growing quickly. For example, data centres, which are among the largest new energy users connecting to our grid, can trigger the need for investment by causing 'spot' load growth in small, localised areas on our network. Other major customers connecting to our grid include large road and rail infrastructure projects.

What we have heard so far

We know that our customers are interested in EVs and see value in relying on more electric devices to heat their homes, offices and hot water systems. They also want us to promote affordability by making sure any new assets will be efficiently utilised.

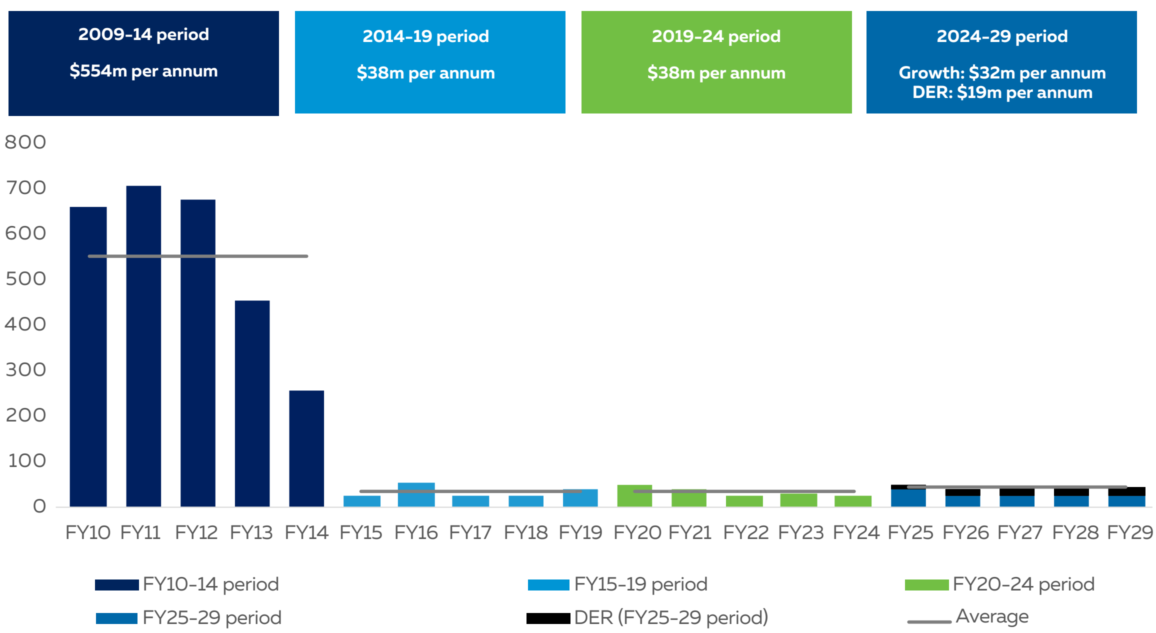
What we are considering

Our demand forecast underpins our investment strategies and ensures that we are investing the right amount in the right locations. Given uncertainty in the pace of change towards greater electrification, our demand forecast considers various scenarios incorporating different emissions pathways, and informs least-regrets investments.

The growth capex forecast put forward in our Draft Plan is 16% below our 2019-24 spend and 35% less than our allowance for that period. This lower level of spend will promote affordability at a time when customers are telling us they are concerned about rising cost of living pressures.

There is a relationship between our growth capex and DER integration capex. This is because our DER capex enablement program (discussed on the **next section**) will deliver more capacity to the grid, complementing our traditional growth capex needs. Due to this relationship, we have set out our growth capex and DER integration investments together in **Figure A.9** below.

Figure A.9 Growth and DER capex ($ million, real FY24)



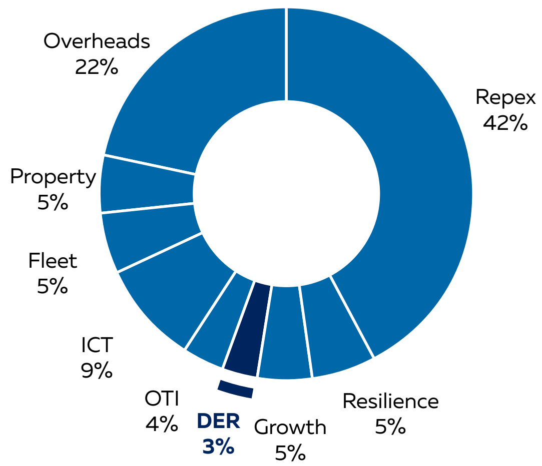
DER integration capex

DER capex is a new expenditure category for our 2024–29 Draft Plan. DER capex supports the forecast uptake of DER, including efficiently connecting an additional 620,000 rooftop solar systems, batteries, EVs or controlled load to our network over the 2024–29 period, and preparing for another 1 million over the 2029–34 period (see **Section 2.2** of the Draft Plan).

Our forecast DER capex reflects the AER's DER Integration Expenditure Guidance Note released in June 2022. This Guidance Note sets out how electricity networks should prepare business cases for DER expenditure for the AER's consideration.

We are considering total expenditure of up to $153 million for DER integration. This comprises $96 million in DER-related network capex (or 3% of total capex) and $34 million in ICT capex on DER enabling technologies, as well as $24 million in smart meter data opex.[2]

Figure A.10 Forecast DER-related network expenditure (only) as a percentage of total forecast capex



What does DER integration capex mean for our customers?

What DER capex means for our customers will depend on which investment approach we adopt. We have been considering 3 alternative approaches: preparatory, proactive or accelerated timeline.

Preparatory investments include:

- Improved network visibility
- Digital tools that improve customers' experience connecting DER and the range of network information available to us

Proactive investments include:

- Preparatory investments noted above
- Innovative connection and pricing options that encourage customers to use their energy assets in ways that put less pressure on the grid
- A mix of traditional augmentation and flexible network solutions, including community batteries

Accelerated timeline investments include:

- Proactive investments noted above, but accelerated network augmentation and rollout of network management devices that, as far as possible, would minimise the need to restrict exports

What have we heard so far

Customers are telling us that:

- They consider an accelerated timeline approach may result in customers facing unnecessary costs; and
- Preparatory investments may be insufficient to address the increase in DER expected on the network and ultimately be less efficient.

What we are considering

Based on what we have heard so far, our Draft Plan is based on the proactive investment scenario.

This approach includes investments that enable innovative pricing options, education and collaboration, network visibility, better voltage management and tailored connection arrangements.

It would enable us to efficiently accommodate our customers' desire for more DER. We would be able to build our capability to integrate DER without over-investing in the network.

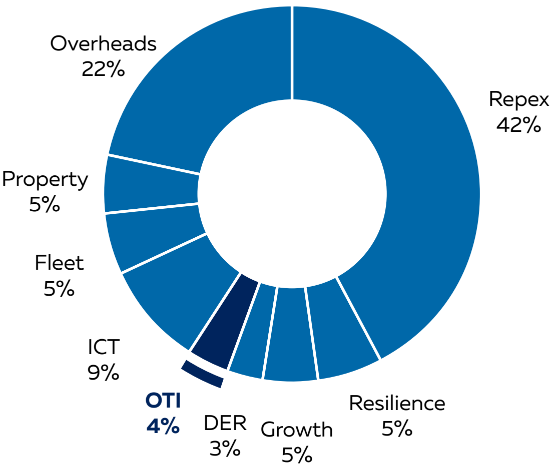
We intend to further test whether we are hearing our customers accurately, and value your feedback on our DER investment approach.

2 Does not sum to $153 million due to rounding.

Operational technology and innovation capex

Our forecast operational technology and innovation (**OTI**) capex of $114 million in the 2024-29 period is 39% lower than the $188 million we expect to spend in the current period.

Figure A.11 Forecast OTI as a percentage of total forecast capex



What does OTI capex mean to our customers?

OTI capex includes investments related to operational technology and an innovation program that covers a range of network technology related research, trials and pilots. Operational technology enables us to directly monitor and control physical devices and processes on our network and to automate manual processes.

Additionally, these operational technology devices and systems can help stabilise our cost base and improve the service we offer customers. This is by introducing smarter, more cost-effective ways of delivering services to customers.

What we have heard so far

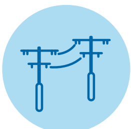
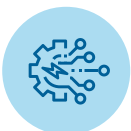
Customers value innovation. The Voice of Community Panel recommended increasing our 2024-29 innovation spend to up to $80 million in capex and $10 million in opex if it did not have a significant bill impact.[3]

What we are considering

We are considering a total innovation investment over the 2024-29 period of $50 million—comprising $45 million in capex and $5 million in additional opex. This is less than the Voice of Community Panel showed support for, but reflective of our 2019-24 allowance in real terms. We consider this to be a 'proof point' that we are taking on board broader customer feedback about the importance of affordability at a time of rising cost of living pressures.

We are also putting in place the arrangements to continue with our Network Innovation Program. As **Figure A.12** shows, this program is currently structured in 3 workstreams, focusing on DER support and enablement, community resilience, and safe and intelligent networks.

Figure A.12 Our Network Innovation Program involves 3 workstreams

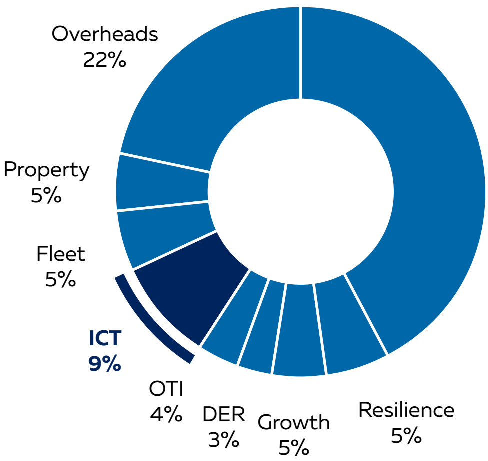
	**DER support and enablement**	• New, untested technology that helps integrate and support more DER to connect to the Ausgrid network – enabling customers to extract more value from their DER assets.
	**Community resilience**	• New, untested technology that helps to increase the resilience of our network and our communities to severe weather events and other incidents such as bushfires.
	**Safe, intelligent networks**	• New field assets that deliver safe, reliable and sustainable energy for our customers; and • Technology and capability that helps us to better plan, maintain and operate the network. This improves our capability to use the increasing quantum of data available to us through customer and network devices.

3 Voice of Community, Ausgrid Panel Report, June 2022, Recommendation 6.

ICT capex

Our forecast ICT capex for the 2024-29 period is $292 million. This represents 9% of our total forecast capex (see **Figure A.13**).

Figure A.13 Forecast ICT capex as a percentage of total forecast capex



What does ICT capex mean to our customers?

In our rapidly changing energy landscape, ICT is becoming the backbone for introducing new services and innovations. Digital tools can help customers interact with us when they have a query or need information about an outage, and can unlock productivity efficiencies.

What we have heard so far

Our customers recognise the benefits that ICT investments can deliver. Our conversations are focusing on balancing affordability with investing in the digital tools we need in a transforming energy market, and having the right level of cyber protections.

What we are considering

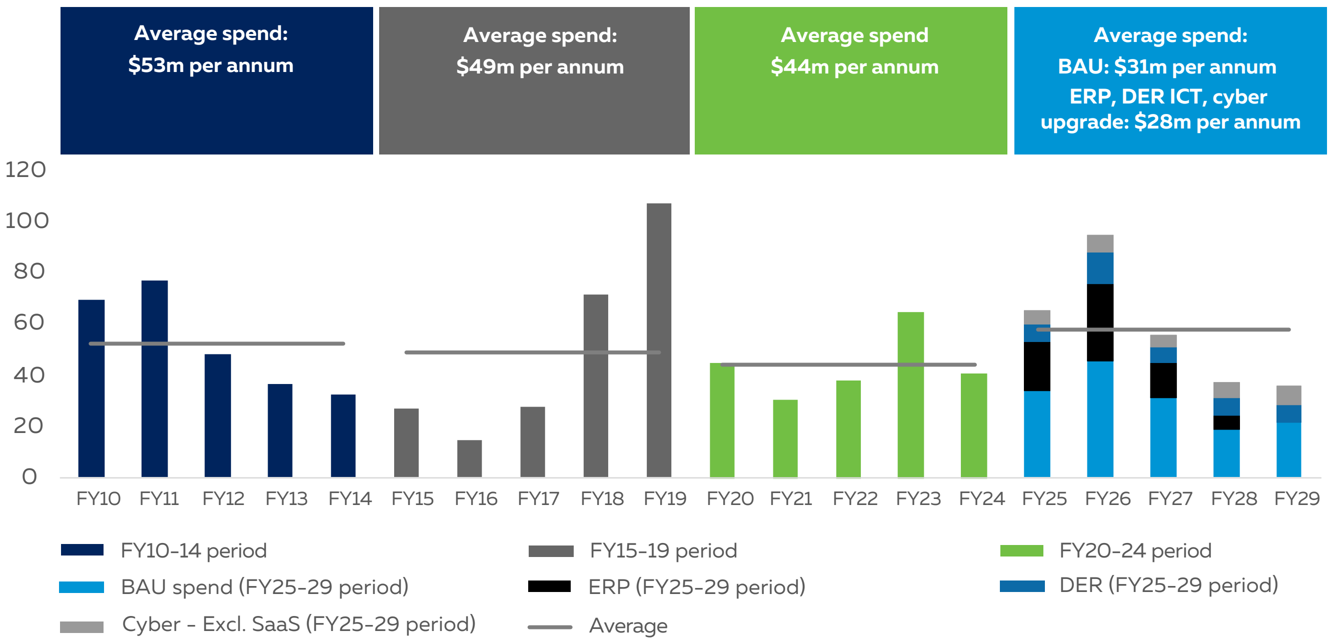
Approximately 53% of our forecast ICT capex is made up of business-as-usual (**BAU**) investments. The remainder is made up of 3 large programs: transforming our enterprise replacement planning (**ERP**) system, investing in DER-related ICT, and upgrading our cyber security.

Our existing ERP was initially deployed in 1996 and parts of it will have been in operation for 31 years by the time of its planned replacement date in 2027.

Many of our digital ambitions for customers, from cost-reflective pricing, to handling customer complaints in a timely manner, depend on not only replacing the ERP but also transforming it (see case study on the **next page** for more information).

Excluding the 3 largest programs, our forecast ICT capex averages $31 million per annum. This compares well to the capex spent in previous years (see **Figure A.14**), in part driven by our migration to cloud-based servers.

Figure A.14 Our forecast ICT capex for 2024-29 is higher than we expect to spend in the current period due to 3 large programs ($ million, real FY24)



Case study: Transforming our ERP will unlock a range of benefits

Our ERP is used by most of our 2,750 staff. It provides the digital platform for making maintenance and investment decisions, answering our customers' inquiries, and operating billing systems.

Transforming our ERP will unlock a range of benefits. This is shown from the perspective of an Ausgrid customer (**Figure A.15**) and our business (**Figure A.16**).

Figure A.15 How transforming our ERP would benefit our customers

Figure A.16 Why transforming our ERP is important to our business

To refresh our existing ERP, parts of which will have been in operation for 31 years (from 1996 to our planned replacement date of 2027)

To ensure our critical business systems are vendor supported – SAP has notified support will not be available on our current version past 2027

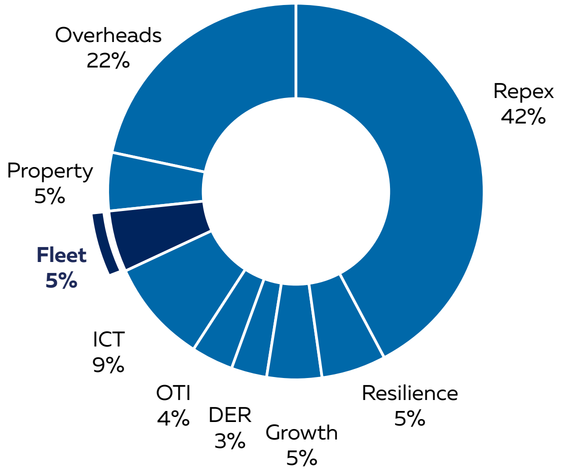
To standardise our business operations in line with practices that are proven, documented, efficient and ready to use

To ensure our ICT systems are cost-effective and resilient

Fleet and plant capex

Our forecast fleet and plant capex of $167 million in the 2024-29 period is 41% higher than the $119 million we expect to spend in the current period. It represents 5% of total capex.

Figure A.17 Forecast fleet and plant capex as a percentage of forecast capex



What does fleet and plant capex mean to our customers?

Our fleet of vehicles and trucks support our operations in the field by providing a safe and reliable mode of transportation. 'Plant' assets refer to the equipment we use in the field—such as elevated work platforms (**EWPs**), vehicle loading cranes, and pole installation equipment.

What we have heard so far

Customers are telling us that affordability is critically important to them. Because of this, customers value investments in tools that drive efficiencies without compromising safety.

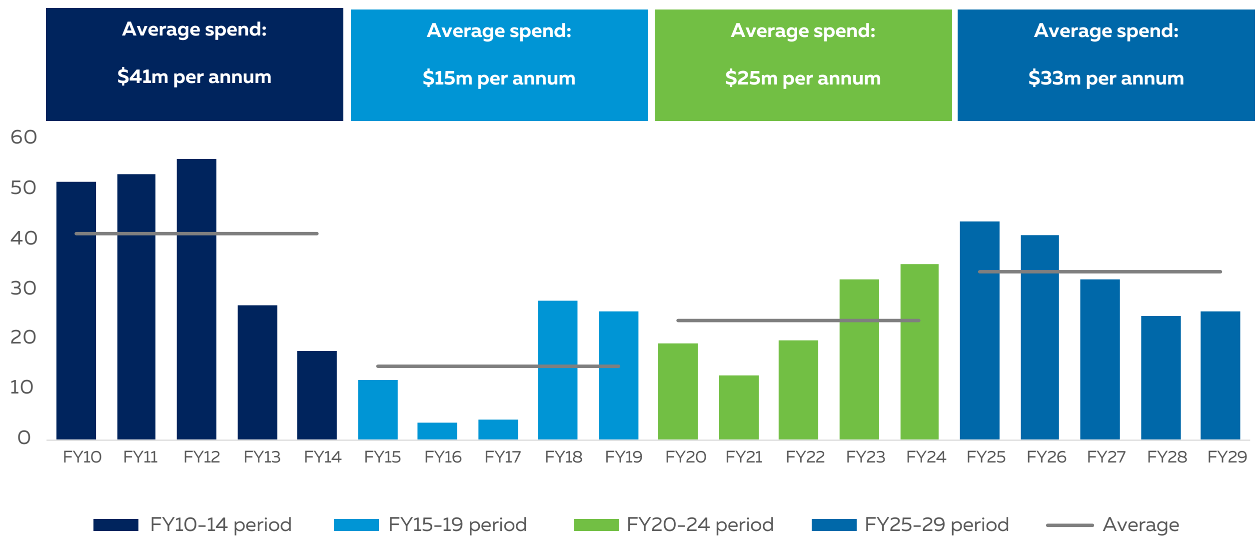
What we are considering

We are considering ways in which we can reduce our total fleet and plant costs. This includes options for reducing maintenance costs and improving fleet reliability.

For light commercial vehicles, our analysis is revealing that maintenance and repairs costs increase after a certain vehicle age. The step change for repair costs is particularly significant. At 6 years, they rise by 52% for utility vehicles and by 193% for vans. We are considering shortening our replacement lifecycle for these assets from 7 to 6 years to achieve cost savings and meet updated safety recommendations from the Australasian New Car Assessment Program.

We are also looking into replacing up to 179 EWPs in the 2024-29 period. EWPs are trucks with a platform attached at the rear which allows our field crews to reach overhead assets. This replacement program would unlock productivity gains for our network capex program and reduce the 20% increase in EWP breakdowns we have been recently experiencing.

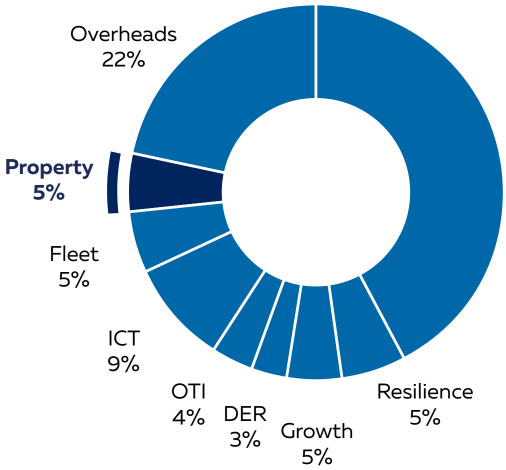
Figure A.18 Our forecast fleet and plant capex in 2024-29 is higher than we expect to spend in the current period, driven by age ($ million, real FY24)



Non-network property capex

Our forecast non-network property capex in the 2024-29 period is $163 million. This is 2% lower than the $167 million we expect to spend in the current period 2019-24.
It represents 5% of our total forecast capex (**Figure A.19**).

Figure A.19 Forecast non-network property capex as a percentage of total forecast capex



What does non-network property capex mean to our customers?

Our non-network property assets include offices, depots and specialist sites located throughout Ausgrid's distribution area. Capex is required to mitigate the risk of safety hazards causing harm to our workforce and the general community.

What we have heard so far

We are hearing that we must be smart about the investments that we make at a time when cost of living pressures are rising. This is particularly the case for high capital cost decisions, like the location of offices and new depots, which cannot be unwound easily.

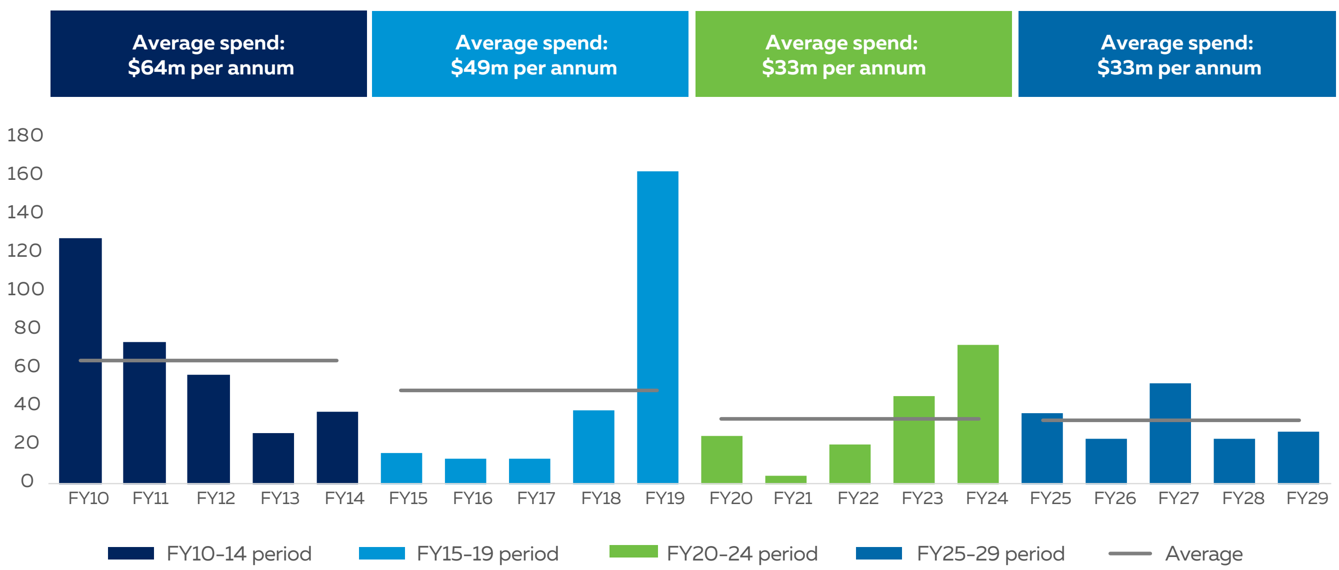
What we are considering

We are completing a target operating model to guide our non-network property requirements into the future.

The analysis feeding into our target operating model takes a long-term view of our property needs. This will promote affordability beyond the 2024-29 period by making the right investments in the best locations to service our customers most efficiently.

Our current non-network property forecast is set out in **Figure A.20**. It shows that our forecast investment in non-network property for 2024-29 period is in line with our 2019-24 period spend and less than our non-network property capex for both 2009-14 and 2014-19.

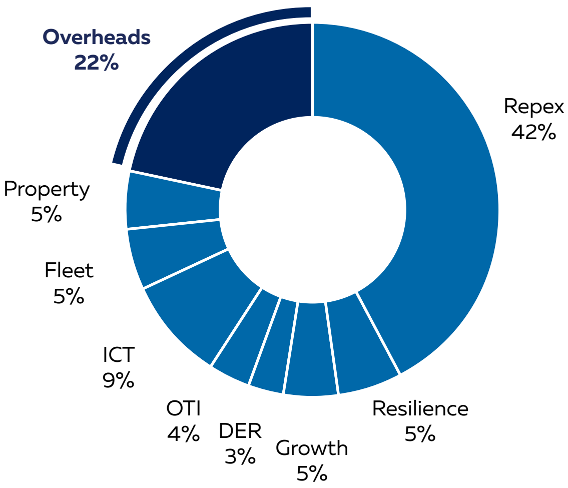
Figure A.20 Our forecast non-network property capex in 2024-29 is higher than we expect to spend in the current period ($ million, real FY24)



Capitalised overheads and delivery

Capitalised overheads make up approximately 22% of our total forecast capex (see **Figure A.21**). They include the indirect costs we incur in the delivery of both our network and non-network capex programs. Examples include network planning and management activities.

Figure A.21 Forecast capitalised overheads as a percentage of total forecast capex



The AER's standard method to calculate capitalised overheads for regulatory determination purposes involves using the historic proportion of capitalised overheads to direct capex and trending this forward. This methodology is based on the AER's view that capitalised overheads are 75% fixed and 25% variable.

We intend to apply the AER's standard approach. Using this approach, we have calculated a capitalised overhead forecast of $700 million in the 2024-29 period.

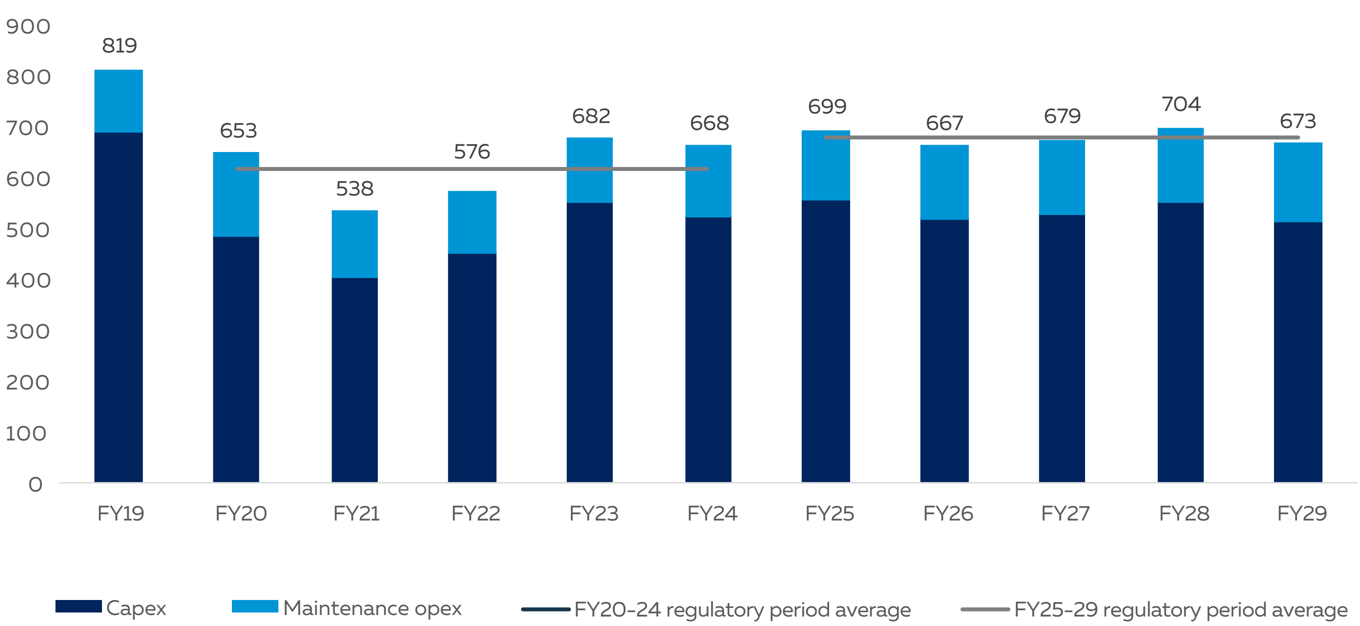
Delivery of our capex program

We employ governance tools to support the efficient delivery of our capex program and ensure that we have the capability and capacity to deliver our investment needs.

Our initial workforce analysis indicates that we do not have enough internal resources to deliver our forecast work plan for the 2024-29 period. The early identification of resourcing gaps allows us to develop appropriate strategies to address them.

Figure A.22 sets out our combined network maintenance and capex program. This provides a fuller picture of our delivery expectations compared against recent years. It shows that our forecast is in line with recent levels, reinforcing that our 2024-29 period planned program is deliverable based on existing capabilities.

Figure A.22 Combined capex and maintenance opex program



Capital productivity

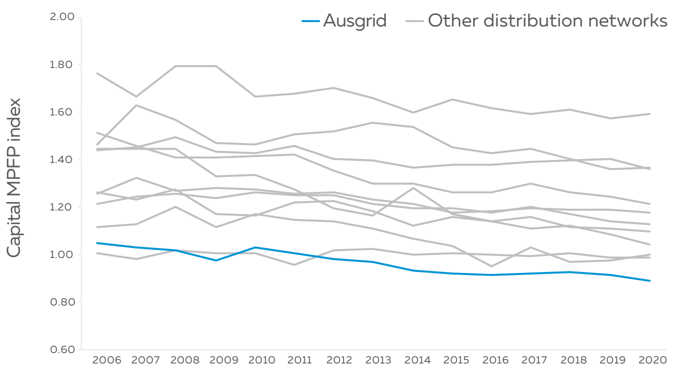
Capital multilateral partial factor productivity (MPFP)

We do not perform well against the AER's published measure of capital MPFP[4] (see **Figure A.23**). We note that there has been an overall decline in capital productivity (on this measure) across the sector over the past 15 years, which is likely because legacy capex decisions remain in the measure for an extended period.

We have been discussing capital MPFP with the RCP. We have come to the shared view that this measure is less relevant for assessing Ausgrid's relative capex efficiency. This is because the measure is driven by historical capex required to meet previously mandated reliability standards. As a result, we cannot move up the rankings simply by spending less capex.

Demonstrating and monitoring our capex productivity remains important. We are discussing alternative measures with the RCP, such as a productivity factor for capitalised overheads, asset utilisation and expenditure and unit rate trends.

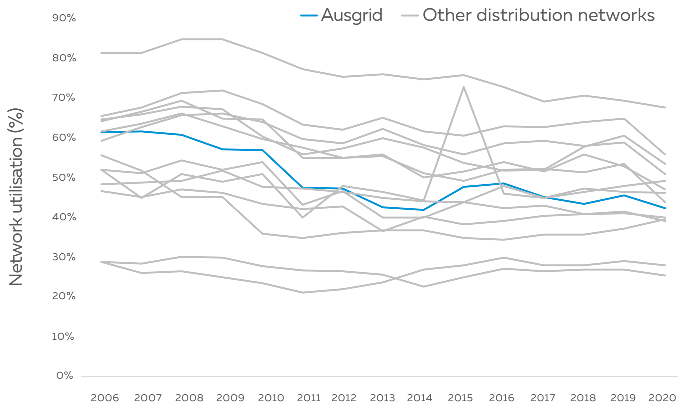
Figure A.23 Capital MPFP Index



Network utilisation

A secondary measure of capex efficiency is network utilisation. Due to historical capex levels, our network utilisation is relatively low and has been consistently declining, as shown in **Figure A.24**. Average utilisation across the sector has also declined since 2006 as more customers use energy-efficient appliances and electricity generated by their own rooftop solar systems.

Figure A.24 Network utilisation



If we can manage capex and customer demand such that utilisation improves, we will not need to spend as much to expand the network. This will keep costs down.

Therefore, we commit to taking steps that target network utilisation over the long term, noting that this metric can be materially affected by factors outside our control – for example, the quantity and location of rooftop solar and batteries connecting to our network.

Consultation question 12:

What is the best way of measuring improvements in the productivity of our capital investments?

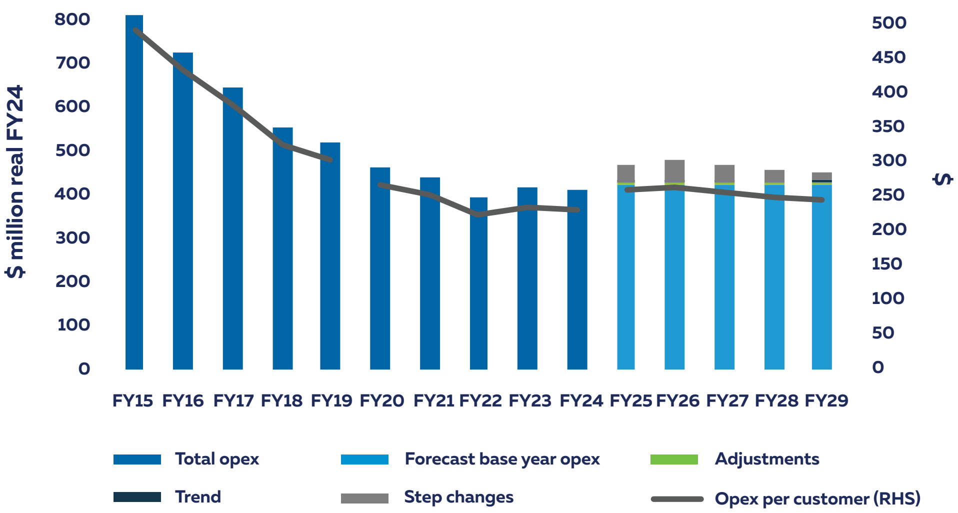
4 MPFP is one of the AER's productivity measures, it measures the ratio of outputs to inputs. The higher the ratio, the fewer inputs have been used to produce a given level of outputs, and the more efficient the outcome.

B 2024–29 operating expenditure

Our draft operating expenditure (**opex**) of $2,254 million, excluding debt raising costs,[5] is 14% lower than our current period allowance and 9% higher than our current period forecast spend.

The annual opex breakdown, excluding debt raising costs is shown in **Figure B.1**. Total opex including debt raising costs is $2,297 million.

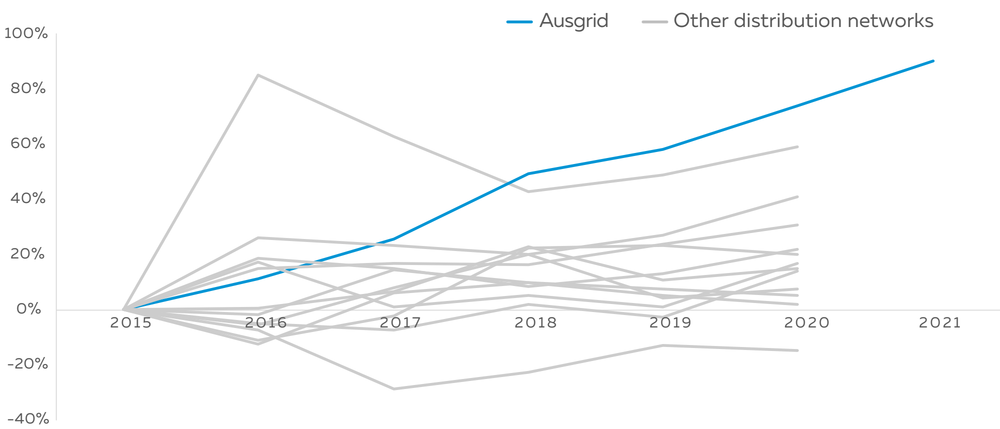
Figure B.1 Forecast opex ($ million, real FY24)



Because of our efforts to reduce opex, we have improved our opex efficiency as measured by MPFP by more than any other electricity network in the NEM (**Figure B.2**).

We expect this to improve even further based on recent performance. We acknowledge the improvement is off a low base – we were ranked 11 out of 13 businesses in the AER's 2021 benchmarking report.

Figure B.2 Percentage change in opex MPFP compared to other network businesses[6]



5 Debt raising costs are added to total opex to cover, for example, arrangement fees, credit rating fees and issuer legal counsel fees associated with the raising of debt.

6 Only Ausgrid shown for FY21 as the benchmarking performance of other networks has not yet been published.

We have estimated opex for our Draft Plan using the base-step-trend method. This is the AER's preferred method for forecasting opex.

Base opex

In recognition that opex is largely recurrent in nature, opex forecasting starts with actual opex incurred in the 'base year'. We have selected FY23 to be our opex base year because it will be the latest actual expenditure available for the AER's final decision. While we do not know what our actual opex will be in FY23, we have set a budget and expect to achieve that budget.

FY23 opex is forecast to be higher than FY22[7] for 4 main reasons:

- FY22 includes a one-off provision reduction ($8 million);
- High inflation ($10 million);
- Higher IT subscriptions and licences ($8 million); and
- Higher maintenance costs ($6 million).

These and other higher costs are expected to more than offset our expected productivity gains of $12 million in FY23.

The efficiency of our base year opex relative to that of other networks is assessed by the AER using complex econometric techniques.

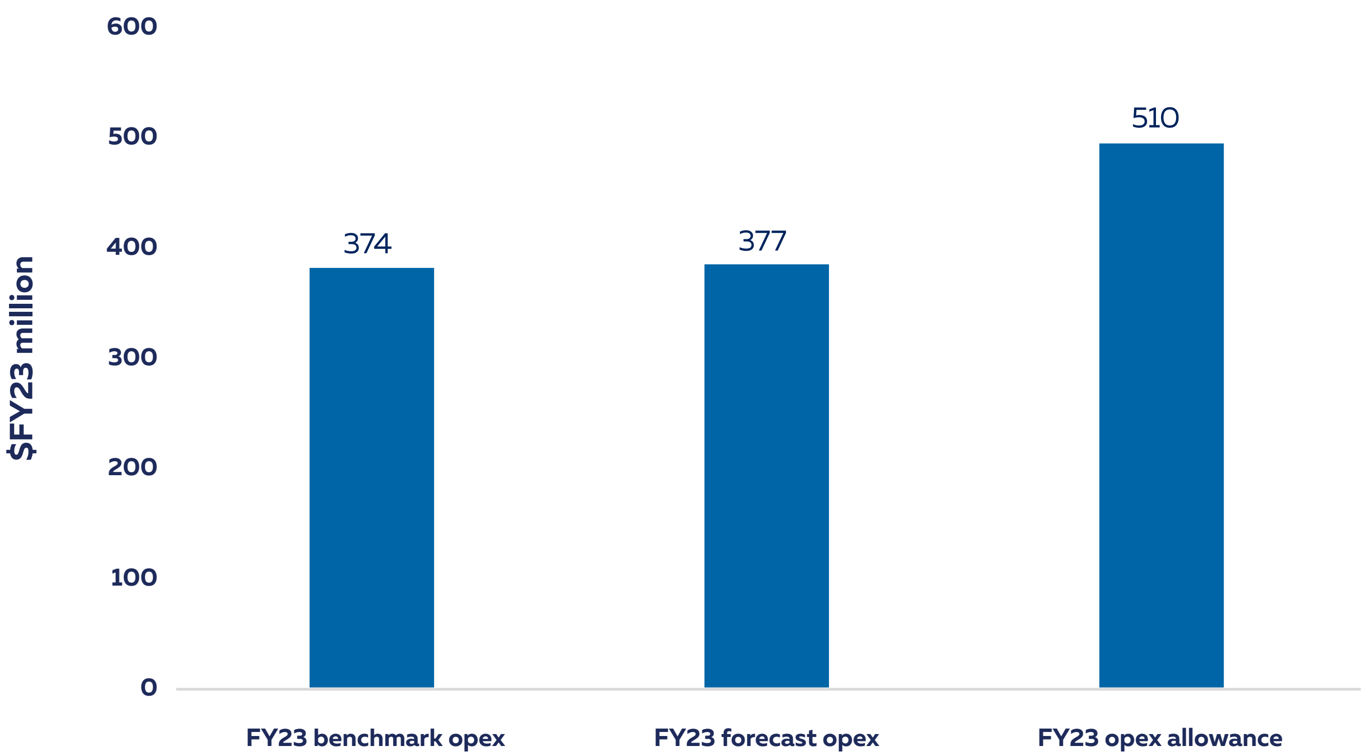
Figure B.3 shows our estimate of efficient opex (based on currently available information) alongside our forecast FY23 opex, excluding SaaS (see the **next section** on 'step changes').

We note that:

- **Econometric models will be updated**: the AER will update its models with FY21 data later in 2022 which will impact these forecasts; and
- **Operating environment factors (OEF) are uncertain**: the AER adjusts data to reflect the differing operating environments across networks (e.g. urban vs rural), and we are still engaging with the AER on these adjustments.

Our current base year opex estimate is within 1% of the AER's benchmark opex level, so we expect it to be deemed efficient.[9]

Figure B.3 Base year efficiency ($ million, real FY23)[8]



7 FY22 forecast as at May 2022.

8 FY23 forecast excludes SaaS.

9 In September we will lodge a revised cost allocation method for AER approval. If approved, our FY23 opex forecast could increase to $383m, still within 3% of the benchmark.

Step changes

The base-step-trend methodology provides for positive and negative step changes to opex for costs that have changed which are outside of our control, or for changes between capex and opex.

Figure B.4 summarises the proposed step changes in our Draft Plan. We have not included all expected cost increases. For example, we propose to absorb higher costs associated with employment of more apprentices and graduates.

Figure B.4 Summary of step change expenditure

Category	$ million, real FY24
Insurance	27.8
Cyber security	18.3
SaaS	68.7
Community resilience	25.0
Smart meter data	23.5
Network innovation	5.0
Total	168.3

Insurance

Our insurance costs are increasing. Key drivers of these increases are climate change, which is causing more damage to networks, and the significantly higher risk of cyber security breaches. Our insurance premiums have increased by 88% over the last 2 years and are forecast to increase another 59% between now and FY29, even with concerted efforts to manage these costs. For this reason, we have included a step change to our insurance costs so we can continue to appropriately manage risk at the lowest sustainable cost. These costs are included in the 'Uncontrollable factors' block in **Figure 1** at the start of these Appendices to our Draft Plan.

Cyber security

As discussed in **Section 4.1.3** of the Draft Plan, we are considering investing in a cyber program that would enable us to adopt practices and protections in line with industry best practice (Security Profile 3 of the Australian Energy Sector Cyber Security Framework). Our Voice of Community Panel did not reach consensus on this point, with some members recommending a more moderate level of protection (Security Profile 2). These costs are included in the 'Cyber' block in **Figure 1**.

SaaS

In April 2021, the International Financial Reporting Interpretations Committee (**IFRIC**) issued a decision on the accounting treatment of implementing SaaS IT solutions.

The IFRIC concluded that the costs associated with configuring and customising SaaS IT solutions cannot be capitalised as an asset if an entity does not control the software. This is a change from our previous accounting treatment where such costs have been capitalised and means that these costs now need to be recognised as opex.

As these costs are non-recurrent or 'one-off', we have forecast the cost of implementing SaaS IT solutions and included them as step changes to base year opex. There is a corresponding reduction to capex. These costs are included in the 'Uncontrollable factors' block in **Figure 1**.

We note that AER staff advised on 8 August 2022 that SaaS expenditure in the current period should be treated as capex for regulatory purposes. This aligns our SaaS expenditure to the allowance for the 2019-24 period. Due to the timing of this notification we were unable to reflect this change in our Draft Plan, however it will be updated for our regulatory proposal in January 2023.

Community resilience

As described in **Section 4.1** of our Draft Plan, we are proposing to employ a range of resilience solutions.

Some of these solutions will involve investing in new assets while others will involve employing new staff with a specialist skillset. These new staff would run outreach programs, provide information about climate resilience and support the communities we serve after an extreme weather event.

Any proposed expenditure will be assessed against our Climate Resilience Framework[10] to ensure it can provide value for money. This expenditure would be an investment to reduce resilience capex that might otherwise be required to manage the impacts of climate change. These costs are included in the 'Resilience' block in **Figure 1**.

10 Our Resilience Framework is also available for consultation [insert hyperlink]

Smart meter data

Smart meter data and real-time smart meter functionality can be used to test safety outcomes on the network, better utilise assets and reduce curtailment of DER customer exports. These costs are included in the 'DER' block in **Figure 1**.

Investing in this data will lead to:

- More efficient growth capex through more granular and timely information, resulting in faster and more accurate decision-making;
- Enhanced safety benefits through neutral integrity monitoring and life support validation; and
- Lower opex through a reduction in customer callouts.

Network innovation

As described in **Appendix A** to our Draft Plan, the Network Innovation Program comprises a range of trials and pilots covering leading edge energy technologies to support the rapidly evolving electricity sector. The program is overseen by the NIAC.

In the 2024-29 period we are considering adding an opex allowance to the program, which will enable us to:

- Select the most efficient options for customers, particularly in the technology domain, with licence costs from the increasing trend towards SaaS and Product as a Service (**PaaS**) offerings; and
- Engage in ongoing research, focusing on community attitudes, expectations and preferences related to issues relevant to the Network Innovation Program, including solution options and equipment standards.

The expenditure is expected to create long-term capex savings through the application of innovative solutions. These costs are included in the 'Innovation' block in **Figure 1**.

Trend

Trend refers to gradual cost changes to reflect the changing nature of the network, due to factors such as increased numbers of customers and assets. For example, an increase in the length of wires and cables operating throughout the network will cost more to maintain. There are 3 main components to trend:

- Productivity factor;
- Output growth; and
- Price growth.

Productivity factor

As discussed in **Section 4.4.1** of our Draft Plan, the productivity factor reduces forecast opex on the basis that businesses will continuously find cost savings. This factor embeds a minimum level of cost reductions that are fully passed through to customers.

Our Draft Plan includes an opex productivity factor of 0.5% per annum, however productivity remains an open discussion with our customers and the RCP.

Output growth

Output growth allows for the increased costs of servicing a growing network. The standard methodology for applying output growth is informed by benchmarking, where opex is adjusted based on growth in:

- Customer numbers;
- Circuit length; and
- Ratcheted maximum demand.

Econometric modelling provides the weighting for these factors. We forecast the change in each factor over the 2024-29 period which drives the output growth. Based on forecasts in our Draft Plan, this contributes around $26 million to revenue over the 2024-29 period.

Price growth

More than half of our opex cost is labour. We have included a placeholder for wage growth in our Draft Plan which adds around $19 million in opex over the 2024-29 period.[11]

11 Source: Deloitte Access Economics national wage price inflation March 2022.

C Regulated Asset Base (RAB) and revenue

RAB

The RAB is the unrecovered value of capex invested in network and non-network assets. It is the basis on which our interest cost and shareholder return allowance (together, 'return on asset') is calculated, and is one of the biggest drivers of our overall costs. **Figure C.1** shows how the RAB is calculated.

As noted in **Section 4.4.1** of our Draft Plan, we expect real asset value per customer to decline over the 2024-29 period.

Based on forecasts for FY23 and FY24, we estimate our opening RAB on 1 July 2024 to be $17.5 billion.

Figure C.1 How the RAB is calculated

Opening value (existing assets)

+

Net capex (capex minus disposals)

+

Indexation (opening value x inflation)

−

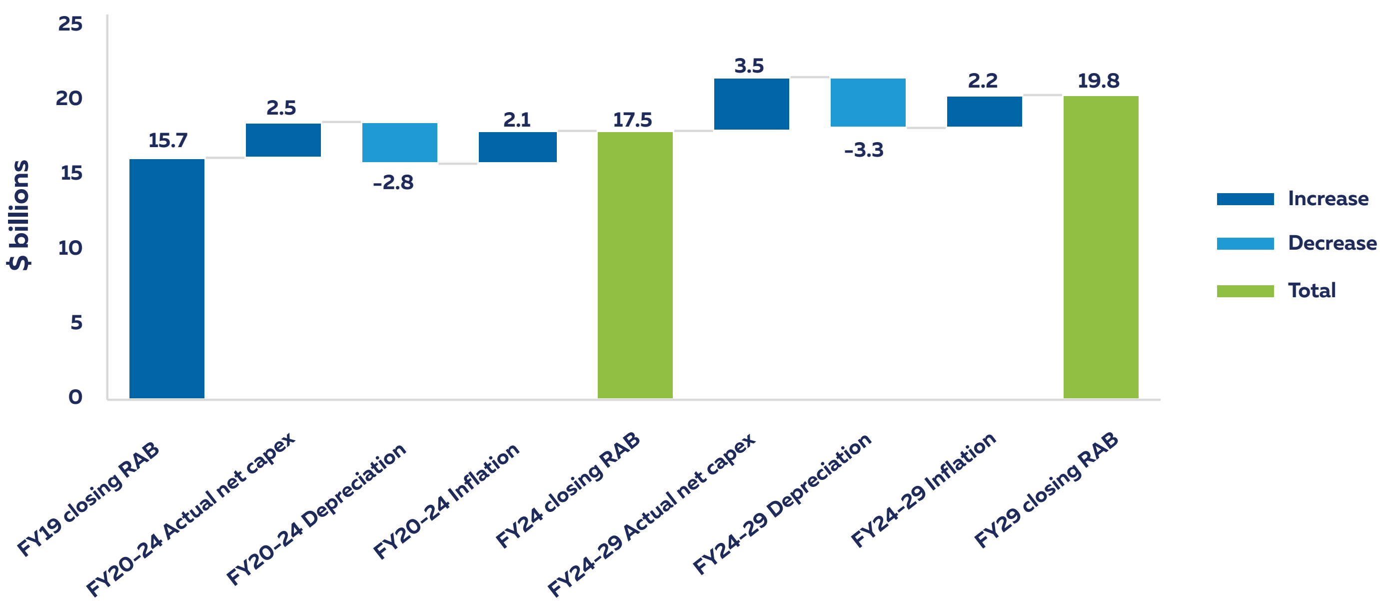
Depreciation

=

Closing balance

Our forecast RAB movements for the current 2019-24 period and the 2024-29 period are shown in **Figure C.2**. RAB is forecast to increase by 14% over 2024-29.

Figure C.2 Forecast RAB (nominal)



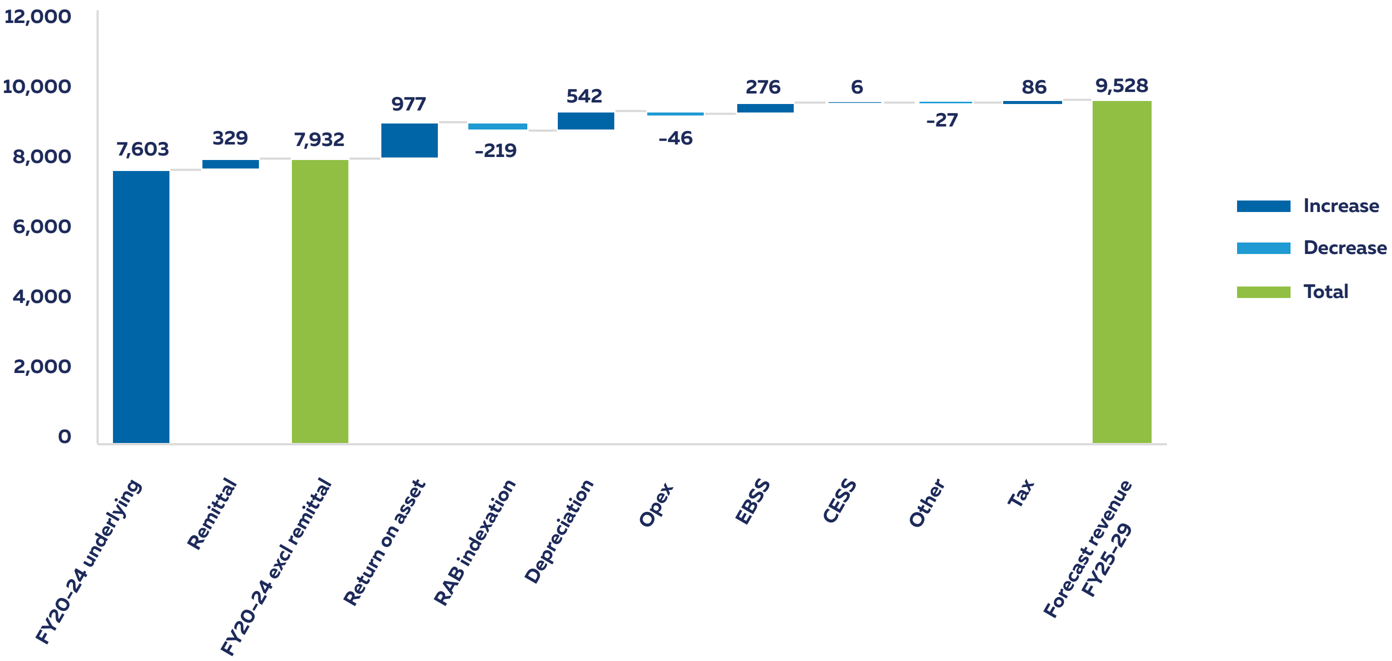
Building block revenue

We are focused on delivering value for money for our customers. However, as noted in previous sections, external factors are having a significant impact on our forecast costs, and therefore the revenue we need to recover to support our ongoing financial sustainability.

Figure C.3 compares each building block component of revenue with the current period.

The first bar on the chart shows total building block revenue for the current period (noting that FY24 is a forecast and will be updated with actual cost of debt in 2023).[12] The final bar shows that the total forecast building block revenue for the 2024-29 period is $9.5 billion. Each component of the forecast revinue is discussed in the following sections.

Figure C.3 Building block revenue change FY20-24 to FY25-29 ($ million, nominal)



12 Revenue was over-recovered in the 2014-19 period by $329 million due to legal action, which meant the final determination was not settled until 2018. This artificially lowered revenue in the 2019-24 period to a starting point of $7,603 million.

Return on asset

More than half of our revenue comes from return on asset. This is the total value of our investments – the RAB – multiplied by a rate of return, or weighted average cost of capital (**WACC**). The WACC covers our interest costs for borrowings that help fund investments, plus a fair return to shareholders.

Figure C.4 shows how the WACC is calculated.

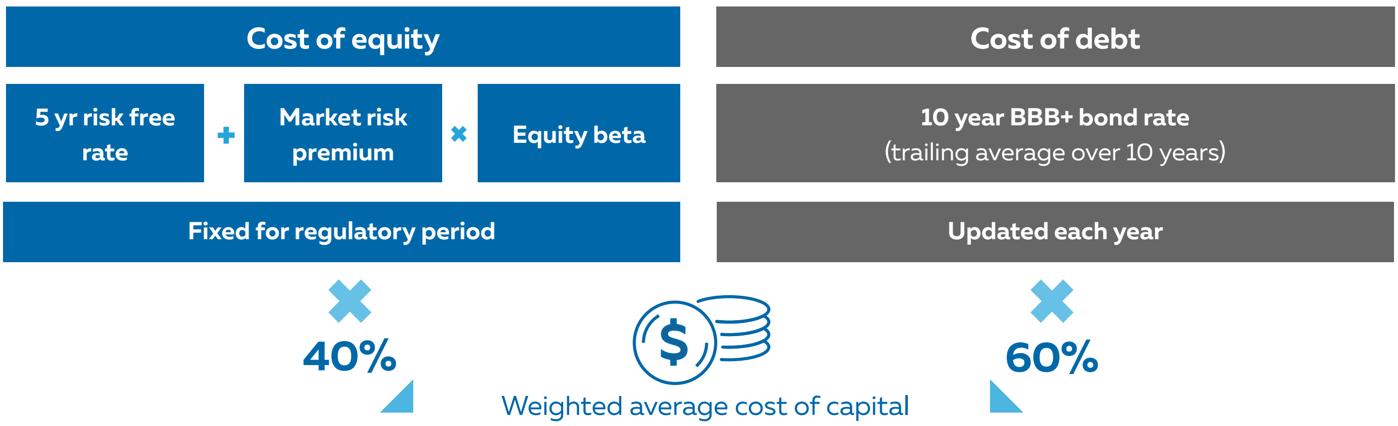
The AER runs a separate process to determine the WACC calculation for all networks. The AER's next decision is due in December 2022 and will apply to us over our 2024-29 period. The AER released a draft of this decision on 16 June 2022 which we support many aspects of.

We note we have a differing view to the AER on the calculation of the risk free rate.

However, current interest rate market data means that there is little difference in the values derived using our preferred approach and the AER's approach. Therefore, for simplicity, our Draft Plan reflects the AER's draft decision on the risk free rate.

The rate of return consists of the cost of debt and the cost of equity. The 2 are combined using a gearing ratio of 60% to create the WACC. In developing our Draft Plan, we assumed an average WACC of 5.8% over the 2024-29 period, compared to an average of 5.3% for the 2019-24 period. The return on asset building block for our Draft Plan is $5,373 million, or 56% of total building block revenue. It is higher than the 2019-24 period mainly due to the higher risk free rate in the WACC and higher RAB balance.

Figure C.4 WACC calculation (based on draft 2022 RORI)



Depreciation

Depreciation allows the cost of investments to be recovered over their useful life so that customers do not need to pay for expensive assets up front. Depreciation is also known as return of asset.

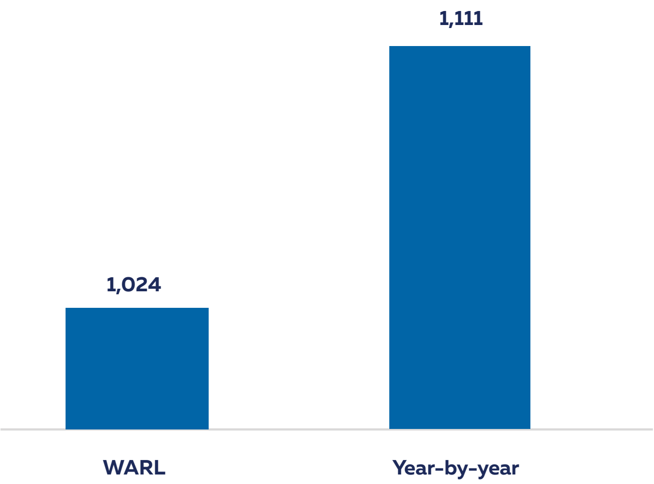
There is a second component included in depreciation to calculate the regulatory depreciation building block. RAB indexation, which compensates businesses for actual inflation, is subtracted from depreciation to ensure that businesses are only compensated once for actual inflation. It is forecast to be $219 million higher in the 2024-29 period, because the RAB is higher. This means there is a higher deduction from depreciation. Our placeholder regulatory inflation is 2.4% per annum.

We are considering changing our method for calculating depreciation from weighted average remaining life (WARL) to year-by-year tracking.

WARL is calculated for the 2019-24 period by weighting the remaining lives of assets existing at the start of the period and the remaining lives of new assets rolled into the RAB during the period by the depreciated value of those assets. At this time in our investment cycle, this results in the dollar value of new assets being given more weighting even though the older assets make up significantly more of the RAB in physical terms. As a result, the WARL method over-estimates the remaining useful lives of all assets within a particular asset class.

Year-by-year tracking does not rely on a WARL but calculates individual straight line depreciation by asset class for each year of capex additions over the life of each asset. Effectively, the assets added each year will be depreciated by their actual remaining life rather than an average including older and younger assets. This change does not impact how much we recover over the life of an asset, but it does change when we recover it.

Figure C.5 Comparison of forecast under each depreciation method ($ million, nominal)



While year-by-year tracking results in regulatory depreciation being $87 million higher than WARL, the overall revenue impact is $42 million due to other interactions in the building block revenue.

Net depreciation is forecast to be $1,111 million, which is 12% of total building block revenue. It is higher than in the current period due to additional capex more than offsetting depreciation of older assets.

Consultation question 13:

While our proposed depreciation change will improve intergenerational equity, it will mean current customers bear a higher cost burden than previously. How should we balance the proposed change with the need for affordability?

Opex

Our forecast opex is explained in **Appendix B** to our Draft Plan. Nominal opex including debt raising costs is $2,468 million and 26% of total building block revenue.

Revenue adjustments

Revenue adjustments are incentive schemes or other adjustments to revenue allowed or required under the National Electricity Rules (**NER**).

Efficiency Benefit Sharing Scheme

The Efficiency Benefit Sharing Scheme (**EBSS**) applied to our current 2019-24 period regulatory determination, which means that any carryover gain or loss will be added to or deducted from 2024-29 revenue. The EBSS did not apply in the 2014-19 period. Therefore, any carryover amount is an increase compared to the previous 2014-19 period.

As discussed in **Appendix B** to the Draft Plan, we have reduced our opex since 2015 and expect to spend less than our current opex allowance in the current 2019-24 period. This means we expect a positive carryover amount to add to revenue in the 2024-29 period. We have calculated this amount using the AER's model and forecast opex for FY23. We currently expect the EBSS carryover in the 2024-29 period to be $276 million, which is 3% of our forecast building block revenue. While we receive 30% of the value of that ongoing saving, customers will receive the benefit of lower ongoing opex allowances.[13]

Capital Expenditure Sharing Scheme

The CESS also applied to our current 2019-24 regulatory determination period. Our net capex is lower than allowance, which has been predominantly driven by exceeding forecast asset disposals.

Proceeds from asset disposals are removed from the RAB, so being incentivised to maximise these proceeds is good for customers. The more the RAB is reduced, the lower the return on assets and future costs to customers.

We have calculated the carryover amount using the AER's model and forecast capex for FY23 and FY24. The CESS has also been reduced to adjust for a capex overspend in the final year of the previous 2014-19 period. This negative adjustment is $33 million. We currently expect the CESS to be $100 million which is 1% of our forecast building block revenue.[14]

Demand Management Innovation Allowance Mechanism (DMIAM)

The DMIAM provides distribution networks with funding for research and development on demand management projects with the potential to reduce long-term network costs.

The DMIAM comprises:

- A fixed allowance of $200,000 ($, real FY17), plus 0.075% of the annual allowed revenue for each year;
- Project eligibility requirements; and
- Compliance reporting requirements.

Our forecast DMIAM is $7 million, which is 0.1% of our forecast building block revenue.

13 This estimate could change based on the AER's advice on how to report SaaS in the current period.

14 Ibid

Shared assets

Under the NER we can earn revenue on network assets used for other purposes. For example, when telecommunications companies attach infrastructure to our poles rather than build additional poles, we can receive rent from those companies. If the amount we earn becomes material, there is a mechanism to return a proportion of the revenue to our customers so that they get some of the benefit of the additional revenue.

We currently expect that the revenue we will receive from these shared assets will become material in the 2024-29 period. Because of this, we have reduced our network revenue by 10% of the shared asset revenue. In our **Draft Plan** this forecast amount is $27 million nominal which reduces forecast building block revenue by 0.3%.

Tax allowance

The last of the revenue building blocks is tax allowance. This allows network businesses to cover tax expenses. We have calculated our tax allowance in accordance with the AER's methodology and forecast $220 million, which is 2% of building block revenue.[15]

15 In October 2020 the Federal Court made a decision relating to the tax treatment of capital contributions and gifted assets in Victoria.Gifted assets subject to the decision were not added to revenue for the purpose of calculating our tax allowance. Our expert tax advice, as discussed with AER staff, indicates that the ruling does not apply in NSW because of the different gifted asset frameworks. Therefore, our Draft Plan revenue includes gifted assets in taxable revenue.

D Demand forecasts

This appendix explains how we are currently preparing the demand forecasts that we will use in our regulatory proposal and Tariff Structure Statement to the AER, due in January 2023.

Establishing the baseline

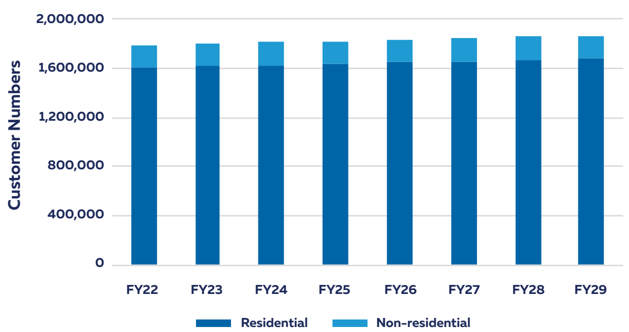
To forecast the demand for our network services over a determination period, we forecast customer numbers, underlying energy consumption, DER, energy efficiency, and major customer loads to generate a projection of overall energy consumption. We use this forecast in several ways – including to project the localised expenditure needs of our network, set our proposed tariffs, and determine the bill impacts for our customers.

Many underlying factors will affect our baseline and demand in the short term. In the current 2019-24 period, the lingering impacts of COVID-19 have led to stronger than expected energy consumption in the residential sector, as many workers delay their return to the office. However, total network energy use is still below trend due to the impact of the 2 lockdown periods on businesses in 2020 and 2021.

Forecasting customer numbers

To forecast our residential customer numbers, we project the growth over the 2024-29 period using the Housing Industry Association's dwelling starts forecast. We forecast our non-residential customer numbers based on recently observed trends. Our current forecast customer numbers for 2024-29 are shown in **Figure D.1**.

Figure D.1 Customer number forecast



Forecasting underlying and overall energy consumption

We use an established model to forecast energy consumption across our network. The model uses actual energy usage data from 2003 and separately estimates consumption for residential and business segments.

The residential projection is driven by household disposable income and a retail price index. Business energy is modelled using gross state product (**GSP**) and a retail price index.

This underlying energy projection is enhanced via specific adjustments for:

- Forecast rooftop solar, batteries and EVs;
- Estimated energy efficiency gains; and
- Major customer loads (such as data centres and rail projects).

Figure D.2 Post-model adjustments for residential consumption, GWh

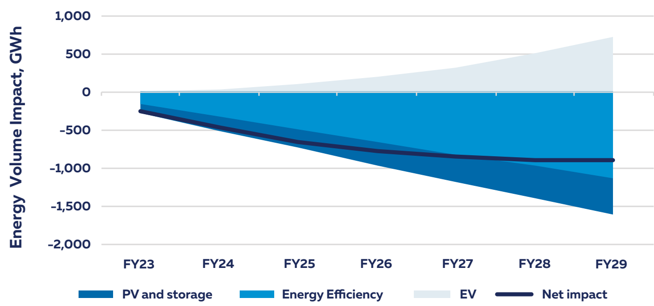
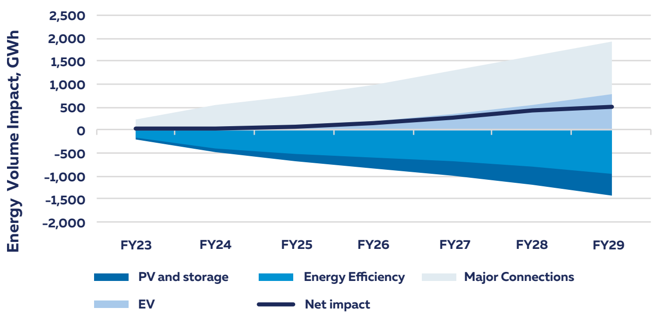


Figure D.3 Post-model adjustments for Non-residential Consumption, GWh



We have developed 4 different forecasts for EV, rooftop solar and battery uptake which are aligned to the 2022 AEMO Integrated System Plan (**ISP**) projections. The consumption forecast uses AEMO's Step Change scenario as the base case.

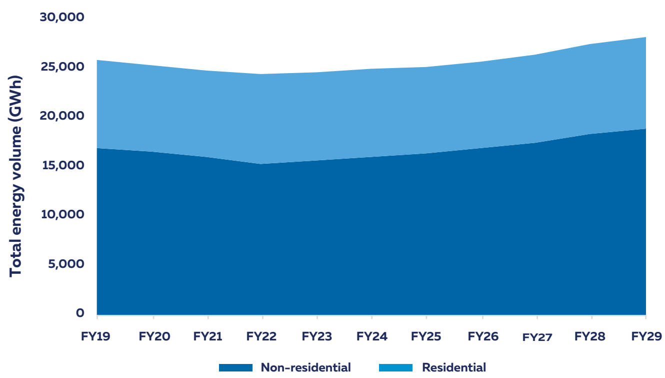
The energy efficiency forecast is aligned with AEMO's Electricity Statement of Opportunities (**ESOO**) 2021 forecast inputs, with 2 exceptions. We have developed updated forecast inputs for the NSW Energy Savings Scheme (**ESS**) and Peak Demand Reduction Scheme (**PDRS**) in line with the latest developments in these areas.

The overall energy consumption forecast is produced by combining the modelled forecast and the separate adjustments.

Our total energy usage to 2029 is expected to decrease by 0.7% between FY19 and FY24, followed by an increase of 2.5% per annum between FY24 and FY29 (see **Figure D.4**).

The COVID-19 related drop in consumption starts to recover post-FY22 due to growth in customers, the general economy, electric vehicles and major connections such as datacentres. These factors are, to a degree, offset by projected energy conservation outcomes due to increasing solar PV penetration, the impacts of the NSW Energy Savings Scheme and improvements in building and electrical appliance efficiency.

Figure D.4 Overall Consumption, GWh



Forecasting smart meter numbers

The rate at which smart meters are installed is an important factor in tariff assignment and revenue recovery for the 2024-29 period. Our forecasts for each tariff depend on the number of customers that have smart meters. We still have around 1 million customers with non-smart meters.

Our proposed tariff assignment policy will see small customers with meter upgrades assigned to demand tariffs. New small customers will be immediately assigned to demand tariffs.

We note that the current AEMC metering review will produce a final recommendation in December this year. The sooner smart meters are installed, the more customers will have the better opportunity to manage their energy use.

For more information on our proposed pricing reforms see our **Pricing Directions Paper**.

E Incentive schemes

We support the application of a balanced package of incentive schemes within the regulatory framework. In general, we consider the current schemes provide a reasonable balance of incentives for electricity distributors.

A stable framework for incentive-based regulation encourages network businesses to continuously identify cost and service level improvements for our customers.

The AER has commenced a review of its incentive schemes. It has released a position paper in relation to the CESS, indicating that it is considering reducing the network share of the ratio from 30% to 20% in certain circumstances.

We propose that the incentive schemes outlined in **Figure E.1** apply to our business in the 2024-29 period. This is the consistent with incentive schemes that apply in the current 2019-24 period, except that it includes 2 new schemes created since the AER's determination for our 2019-24 period:

- CSIS (a new scheme introduced since our last determination) replaces the customer service element of the current Service Target Performance Incentive Scheme; and
- The export services incentive scheme.

Figure E.1 Proposed incentive schemes

Proposed incentive scheme	Description
Service Target Performance Incentives Scheme (STPIS)	See next section.
Incentive scheme for export services	This incentive scheme has been identified for development by the AER. It is intended to provide appropriate incentives for service quality for customers who export electricity to our network. The AER is consulting on new arrangements for incentivising and measuring export services with a final decision currently expected in December 2023.
Efficiency Benefit Sharing Scheme (EBSS)	The EBSS provides network businesses with a continuous incentive to pursue efficiency improvements in their operating expenditure and provide a fair sharing of these between a distributor and network users. Customers benefit from efficiencies through lower costs into the future. We may propose some exclusions from the EBSS based on discussions with the RCP, for example for innovation.
Capital Expenditure Sharing Scheme (CESS)	The CESS provides network businesses with a continuous incentive to undertake efficient capital expenditure throughout the regulatory control period by rewarding efficiency gains and penalising efficiency losses. Customers benefit from efficiencies through lower return on asset and depreciation in future regulatory control periods. We may propose some exclusions from CESS based on discussions with the RCP, for example for innovation, consistent with the current period.
Demand Management Innovation Allowance Mechanism (DMIAM)	The DMIAM provides network businesses with funding for research and development in demand management projects with the potential to reduce long-term network costs.
Demand Management Incentive Scheme (DMIS)	The DMIS provides network businesses with an incentive to undertake efficient expenditure on demand management initiatives that do not involve increasing the size of the network. The DMIS contains 3 elements: • A cost uplift on expected costs of efficient demand management projects; • A net benefit constraint, which ensures the incentive payment for any project cannot be higher than that project's expected net benefit; and • An overall incentive constraint, which limits the total incentive in any year to 1% of the distributor's allowed revenue for that year.
Customer Service Incentive Scheme (CSIS)	A new incentive scheme to enhance customer service, co-designed with customers to focus on areas of service that are most valuable to our communities. More detail is contained in **Section 4.3.1** in the Draft Plan.

Service Target Performance Incentive Scheme (STPIS)

The purpose of STPIS is to provide a financial incentive for distributors to maintain and improve service performance where it provides value to customers. This is intended to counterbalance any incentives distributors may have to reduce costs at the expense of reliability and customer service levels.

STPIS components

The AER's STPIS comprises 2 components:

- A service factor (**s-factor**) adjustment to the annual revenue allowance that rewards (or penalises) distributors for better (or worse) performance compared with a predetermined target for supply reliability and customer service, set by the AER; and
- A guaranteed service level (**GSL**) component whereby customers are paid if they experience a service below a predetermined level, set by the AER.

The STPIS currently applies to Ausgrid. However, the GSL component does not apply as there is a jurisdictional GSL scheme in place for our customers, set out in our licence conditions under the *Electricity Supply Act 1995* (NSW).

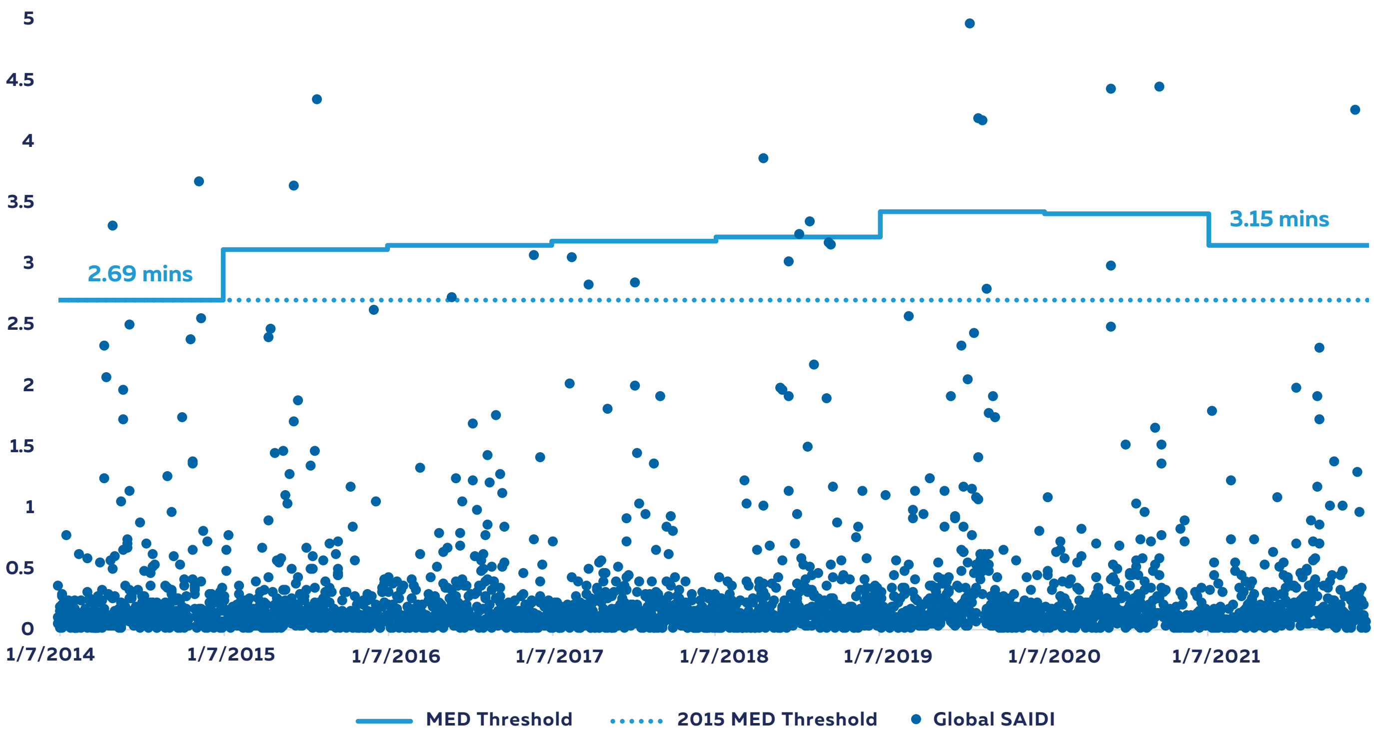
We are also considering proposing a CSIS to the AER (see **Section 4.3.1** of our Draft Plan). If we decide to do this, and the AER accepts this proposal, the new scheme would replace the customer service component of the STPIS.

STPIS exclusions

A key component of the STPIS methodology is the major event days (**MED**). MEDs exclude extreme events like major storms from the calculation of the rewards and penalties we receive under the STPIS. However, this does not adjust for the impact of extreme events in calculating the MED threshold itself. This can have a distortionary impact.

The impact of including major events in calculating the MED threshold is shown in **Figure E.2**. Significantly, it shows that the MED threshold, which was 2.69 minutes in FY15, has now increased, under the AER's method, to 3.15 minutes. Further, it highlights that since FY15 there have been 9 major events on our network which would have been excluded under the FY15 threshold, but are included in our current 3.15 minute MED threshold. We are investigating this issue further, particularly given the expectation that the changing climate will result in more extreme weather events. Other changes should also be considered, such as the automatic exclusion of declared natural disasters from the STPIS.

Figure E.2 Major event day threshold plotted with network-wide (global) SAIDI performance



F Cost pass throughs

Cost pass throughs allow us to recover any material costs incurred from unforeseen events. This includes the additional costs associated with natural disasters, which cannot be predicted ahead of our regulatory determination.

Nominated cost pass through events we are considering

Our current position is to put forward the same nominated pass through events as our 2019-24 regulatory proposal. These are:

- Insurer's credit risk;
- Insurance coverage;
- Natural disaster; and
- Terrorism.

We have an opportunity to suggest the wording that defines each nominated pass through event. This will require particular attention to the definition of a 'natural disaster'.

Revisiting the cost pass through framework for natural disasters

Through our engagement with our communities to date, we have heard from customers that they are interested in how the regulatory framework can be reviewed to ensure it considers the impacts of climate change.

Building climate resilience and adapting to the impacts of climate change continue to be increasingly important considerations for our business, as noted in our 2022 consultation paper with other DNSPs.[16] We note that MED calculations may change and a new Widespread and Long Duration Outages (**WALDO**) events may be introduced. This is important to establish the appropriate regulatory settings in a climate where extreme weather events are becoming more common.

Customers are telling us that they want us to prioritise building climate resilience. We recommend revisiting the cost pass through framework to accommodate natural disaster events that are not one large, isolated event (like a cyclone), but a series of cumulative events.

One way this could be achieved is by drawing a stronger link with how a government authority may have defined the event. For example, the natural disaster event could be defined as:

Natural disaster events will include, but may not be limited to, natural disasters declared by a relevant government authority. Where a government authority has made a declaration that a natural disaster has occurred, the temporal and geographic scope of the natural disaster event will be defined by reference to the terms of that declaration.

Consultation question 14:

Do you have any views on the definition of the natural disaster pass through event?

16 NSW/ACT/TAS/NT Electricity Distributors (2022). Collaboration Paper on Network Resilience.

G Service classification

As we are a regulated monopoly, the AER classifies the services that we can provide to customers and in what form we can supply them.

The AER's 29 July 2022 Framework and Approach decision sets out the AER's intended service classification for the 2024-29 regulatory control period.

Proposed new services

We proposed new services for a few items including system support services, leasing out spare capacity in community batteries and export services.

System support services

Along with Endeavour Energy, we requested a new service grouping called 'system support services' to reflect our role as a distribution system operator (**DSO**).

In its decision, the AER identified that our proposed 'system support services', which the AER did not approve, may be subject to a possible 'material change in circumstances' mechanism. This means that the AER may update Ausgrid's Classification of Services at either the draft or final determination stage to recognise 'system support services' as a classified distribution service. It provides the AER and network businesses more time to incorporate broader Energy Security Board post-2025 reforms that will come into effect during the 2024-29 period and classify them appropriately as services.

We support the AER's approach to revisit this service classification as a material change in circumstances in step with the post-2025 reforms to the NEM.

We intend to continue to recommend to the AER that it use the material change in circumstances mechanism for community batteries and system support services.

Leasing out spare capacity in community batteries

The AER has determined it will not classify leasing out spare capacity in community batteries as a service and the AER's Ring-fencing Guideline (Electricity distribution) currently prevent Ausgrid from providing community battery services without a waiver.

However, we could provide these services if the AER was to classify the facilitation of excess battery capacity as a standard control service (**SCS**). This would require a future update to the Ring-fencing Guideline and the AER using the material change in circumstances provisions.

We propose to continue to recommend to the AER that from 1 July 2024:

- Facilitating the leasing out of spare capacity in a platform asset is classified as a SCS;
- Using the leased capacity in a platform asset (by a third party) remains an unregulated service.

We will continue to share our thinking on community battery cost and revenue allocation with the AER and key stakeholders.

Export services

We support the AER's approach to treat export services as a SCS.

For more information, or to make a submission go to:

YourSay.Ausgrid.com.au