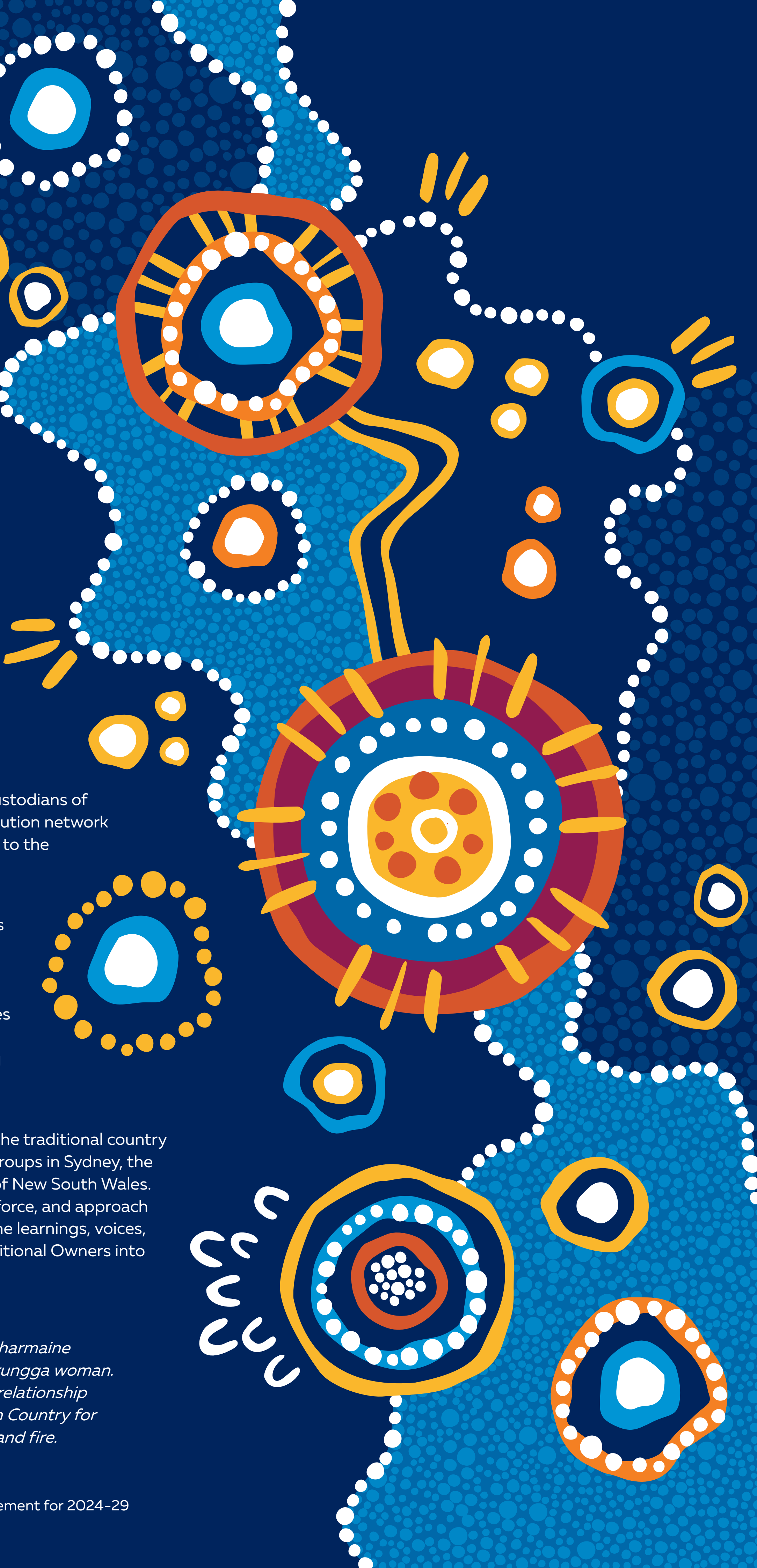
November 2023

Our revised TSS Explanatory Statement for 2024–29

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

Ausgrid



Acknowledgment of Country

We acknowledge the Traditional Custodians of the lands where the Ausgrid distribution network is located, and we pay our respects to the elders past, present and emerging.

As set out in our Reconciliation Action Plan, it is important that this recognition leads to industry wide support and understanding of the knowledge, stories, languages and experiences of Aboriginal and Torres Strait Islander peoples, as our way of paying respect, and contributing to, some of the oldest continuous cultures of the world.

Our network and operations span the traditional country of 17 languages, tribal and nation groups in Sydney, the Central Coast and Hunter regions of New South Wales. We want to lead and foster a workforce, and approach to our operations, that embraces the learnings, voices, cultures and histories of these Traditional Owners into our own organisation.

Artwork designed for Ausgrid by Charmaine Mumbulla, a proud Kaurna and Narungga woman. The artwork explores the dynamic relationship of energy sources and pathways on Country for Aboriginal People – sun, lightning, and fire.

Contents

Executive summary

This revised TSS Explanatory Statement responds to the AER's draft decision as published on 28th September 2023. We have included further information on:

- Our embedded network tariffs and stakeholder consultation (**Section 4.2** and **Attachments 8.13 and 8.15**);
- Our pricing approach for individually calculated tariffs (**Attachment 8.1**);
- Our tariff assignment for medium business customers (**Section 4.3**);
- Our import long run marginal cost (LRMC) in areas where demand is falling (**Attachments 8.1, 8.4 and 8.6**); and
- How our controlled load and trial tariffs can be used for EV charging (**Section 3.1**).

We have published an export tariff factsheet (**Attachment 8.14**) which includes case studies, bill impacts and worked examples for this new pricing structure. We have also provided information on how the AER's draft decision on our Enterprise Resource Planning (ERP) project impacts tariff innovation and reform (**sections 3.2 and 4.5**). Details of our ERP upgrade program can be found in **Attachment 5.9.1**.

As the provider of the poles and wires delivering electricity to homes and businesses across large parts of Greater Sydney, the Central Coast and the Hunter, Ausgrid plays a pivotal role in connecting communities and empowering the lives of over four million Australians. Our network provides a platform for customers to make choices based on what is important to them, be that affordability, decarbonisation, or other priorities. Because of this, we need a strong plan for our future network prices.

In 2019 we introduced new demand tariffs for households and small businesses, which offered our customers lower bills for spreading out the use of electrical appliances. Further pricing reform is required to support the evolving needs of our changing sector. We need to get ahead of the changes facing our customers, our industry, and our world. Rising temperatures and more frequent and severe bushfires, floods and storms mean the effects of climate change – and the need for a net zero future – are more apparent than ever before. New ways of living and working are leading to new patterns of energy use and customers are expecting individualised and affordable, zero emissions energy solutions. These changes create new opportunities for customers to be rewarded for using the network more flexibly. This improves utilisation of the grid, lowering the overall cost of the system.

1.1 Pricing reform is a significant opportunity

We want to maximise the opportunities for retailers and other partners, such as aggregators, to reward customers for their flexible use of the grid. We are building on reforms we have already introduced, such as trialling new incentives for customers to realise the shared value of rooftop solar, home batteries and electric vehicles. Digitisation will facilitate 'prices for devices', a future where retailers and aggregators leverage advanced computing to manage any network tariff complexity, so customers do not have to. Our data-driven initiatives, such as Project Edith[1] and our Customer Energy Resource (**CER**) integration strategy, are also showcasing the potential of new green technology solutions such as Virtual Power Plants to decarbonise the system at lowest cost.

Ausgrid remains committed to delivering options that cater for our diverse communities and customers who use our network. We appreciate that our customers' access to new technology will vary. We know customers and our partners expect an orderly transition that supports choice and involves solutions that set us on the right path for the long term. We will always balance innovative options with simple solutions and ensure customers are supported through change. We will continue building trust with the community through leadership and a clear commitment to support a fair, affordable, resilient and decarbonised system for the benefit of all.

We can only unlock these opportunities if we work together. Ausgrid is excited to collaborate with Governments, retailers and other partners to explore and communicate solutions, so all customers can benefit from the opportunities on offer, if they choose to do so.

Together we can improve the outcomes for NSW electricity customers and the communities we serve.

We have conducted extensive engagement with our communities, to guide and inform us as we develop our revenue, expenditure and pricing proposals for the 2024-29 period. This revised TSS Explanatory Statement provides information on our pricing reforms and tariff innovation to support our TSS compliance document.

1 Project Edith is an initiative that aims to showcase how the grid can facilitate technology and green energy solutions like Virtual Power Plants to participate in energy markets while responding to dynamic network pricing. See our website for more information.

1.2 Our proposed pricing reforms for 2024-29

We have developed a set of pricing reforms that respond to the changes and opportunities in the energy sector in the 2024-29 period, and reflect what we have heard from our customers and communities. Our key proposals are outlined in **Table 1** and describe what has changed since publication of our initial Proposal and the AER's Draft Decision. Each topic is discussed in detail in **Chapter 3** of this paper.

Table 1: Proposed pricing reforms from 1 July 2024

Reform	What and why	What has changed since the initial Proposal
Tariff streamlining	Withdraw 10 network tariffs that are very similar to other tariffs, or have few or no customers assigned to them. This will increase the likelihood of our tariff offerings being passed through by retailers or responded to by market aggregators.	We seek to amend our initial proposal and assign customers on introductory TOU (EA011/EA051) to the introductory demand tariffs (EA111/EA251) for 12 months, before the assignment to "standard" demand tariffs. This amendment will improve the customer experience when moving to demand tariffs and has been triggered as a result of feedback from a retailer. See **Section 4.3**.
Export tariffs	Introduce opt-in export pricing for small customers in July 2024, and make it the default assignment for new and existing[2] small customers on time of use (**TOU**) tariffs and demand network tariffs who are export capable from July 2025. Our proposed tariff has a charge and a reward component. The proposed level of the charge is low, and we expect it to have minimal bill impacts over the 2024-29 period. We want to empower customers to use the network and maximise the value they get from self-generation, benefiting from being flexible, and facilitating the transition to net zero.	In response to the AER's Draft Decision, we have published an export tariff factsheet with a worked example and case studies including network bill impacts by customer type (**Attachment 8.14**). It incorporates feedback from our PWG and VoC groups. We have also amended our assignment policy for the export tariff so that it only applies to customers who have an approved network connection with export capability. The tariff code is also updated to EA029.
Sub-threshold (trial) tariffs	Ausgrid currently has several sub-threshold tariffs available for retailers. These trial tariffs examine customer responses to innovative pricing structures such as critical peak prices, different time-of-use periods, and reward-based export tariffs.	We plan to introduce a Local Use of System (LUOS) sub-threshold tariff in July 2024. This tariff will test whether incentives for customers located near a community battery will encourage participation in a related retailer product.
Small customer tariff assignment	The tariff assignment policy in our initial and revised Proposals allows small customers moving to demand tariffs to access introductory demand tariffs (EA111 and EA251) for 12 months.	As outlined in the Draft Decision, we confirm that the 12-month transitional demand tariff will be available to any customers whose meter is replaced due to a NER amendment triggering an accelerated roll out.
Embedded network pricing	Introduce 3 tariffs for embedded networks (**ENs**) with medium or large annual energy usage with a five-year transition period. These will be the default tariffs for new and existing ENs connected to our network from 1 July 2024.	In response to the AER's Draft Decision, we have included further details of our stakeholder engagement on EN tariffs, commentary on the proposed tariff component structure, and published a model estimating the extent of the tariff arbitrage (**Attachment 8.13**). We have also considered whether any network costs are avoided as a result of ENs, and found that they are minimal and should not be included in our EN tariffs.

2 NER, clause 11.141.1 defines an existing CER customer as one that was connected as of 19 August 2021

Table 1: Proposed pricing reforms from 1 July 2024

Continued

Reform	What and why	What has changed since the initial Proposal
Utility scale storage	Introduce tariffs for utility scale storage facilities connected at our sub-transmission, high and low voltage parts of our network. This will enable storage projects to connect to our network where there is existing capacity and reduce network charges for other customers by contributing to residual revenue.	We have amended the tariff codes for the proposed storage tariffs and renamed the "N reliability measure" as the "network reliability measure". The AER's Draft Decision on the Enterprise Resource Planning (ERP) platform provides for only $18 million (instead of the proposed $149 million). We consider it is unlikely we will have capability to apply these tariffs on a locational basis in the 2024-29 period.
Business customer tariff assignment	Lift the lower usage threshold at which capacity charges apply from 40 MWh to 100 MWh. This change will align with the NSW ombudsman scheme and the National Energy Retail Law Regulation 2020 (NSW) definition of a small customer. It will also improve available options in our tariff assignment process for small business customers.	In response to stakeholder feedback we are proposing to allow more customers to access demand and TOU tariffs. We have included further commentary to support this change in **Section 3.3**. We have also removed the "100 amp" rule to avoid inconsistency with this change.
Controlled load	Change the switching times for controlled load devices to allow customers to use these devices during the daytime, when solar customers are exporting to the grid. This proposal will encourage soaking of solar exports during the day, improve network utilisation, and potentially reduce greenhouse gas emissions, improving pricing efficiency and supporting the transition to net zero.	We have amended our assignment policy for the new switching times so that they are only available for customers with capable metering.
Charging windows	Move our peak period window to later in the day for customers on TOU and demand/capacity network tariffs, and extend it to weekends for residential customers. These changes will ensure our peak charges accurately signal the periods when these customers' energy use imposes highest costs on the network, improving pricing efficiency and fairness.	No changes to our proposal.

To help implement these reforms we are proposing transitional arrangements, which mostly apply in the early years of the regulatory period, depending on the measure. By the end of the regulatory period, our overall tariff strategy will include the following core features:

- All customers with a smart meter are assigned to a cost reflective network tariff;
- Cost reflective tariffs are available for utility scale storage facilities;
- All customers on TOU, demand or capacity tariffs have simpler tariffs to encourage retailer pass through– with only two charging windows, peak and off-peak;
- All residential and small business customers are assigned to modest export pricing arrangements – incorporating both charges and rewards depending on the time of export; and
- All embedded network connections connected to the LV network (with annual consumption >160 MWh) or connected to the HV network are assigned to embedded network tariffs.

We note that our proposal of $12.1 million for systems to support dynamic operating envelopes and dynamic pricing has not been approved. This would prevent us from pursuing Project Edith to support market integration of CER and facilitate efficient network support to reduce future expenditure.

Introduction

As the provider of the network that delivers electricity to homes and businesses across large parts of Greater Sydney, the Central Coast and the Hunter, Ausgrid plays a vital role in connecting communities and empowering the lives of more than four million Australians.

How we charge customers for our network services can influence when and how customers use electricity and give them flexibility to choose what is important to them – for example, convenience, lower bills, or lower carbon emissions. Our pricing can also influence the costs we incur in providing our services, and how we recover those costs from different customers – for example, the extent to which our pricing reflects the higher or lower costs that patterns of electricity use impose on the network, or result in some customers paying more or less than their fair share. Because of this, we are proposing a comprehensive plan for our future network prices, which takes into account customer and stakeholder views.

2.1 Purpose of this document

This revised TSS Explanatory Statement supports our TSS compliance paper and provides further detail on our pricing reforms and pricing innovation proposals for 2024-29.

The sections that follow outline:

- The challenges and opportunities in the energy sector our proposed pricing reforms are responding to;
- How we have engaged with our communities to inform the development of our TSS;
- Our proposed pricing reforms for 2024-29, including how they meet our pricing principles and respond to what we are hearing in our engagement with our communities;
- Our proposed tariff innovation for 2024-29, including tariff trials to test and guide future pricing reforms; and
- Where we think our network tariffs are heading, as we look beyond 2030.

Throughout these sections, we provide and respond to the feedback we have received from stakeholders, either via submissions, Pricing Working Group (**PWG**) meetings, the retailer forum, or our meetings with customers.

2.2 Our current network prices

We have different network prices for our residential and small business customers and for our medium and large business customers.

For residential and small business customers, retailers package up our prices with the other costs of electricity supply – including wholesale, environmental and retail costs. Retailers' pricing structures might mirror the structure of our network prices, or have another structure entirely.

Historically, most of our residential and small business customers have been on network prices with a flat energy-based structure, which means they paid a fixed rate for every kWh of electricity they used. This is because older electricity meters only recorded the amount of energy used over time. However, this flat tariff structure:

- **Is not cost-reflective –** our costs are not driven by how much energy our customers use over time, but by how much energy our customers use **at the same time** (the peak demand on our network). Our costs are also expected to increasingly be driven by the amount of energy customers export to the grid at the same time.
- **Does not give customers much control over their bills –** with a flat energy-based structure, the only way customers can lower the network cost component in their bill is to lower their overall energy usage.

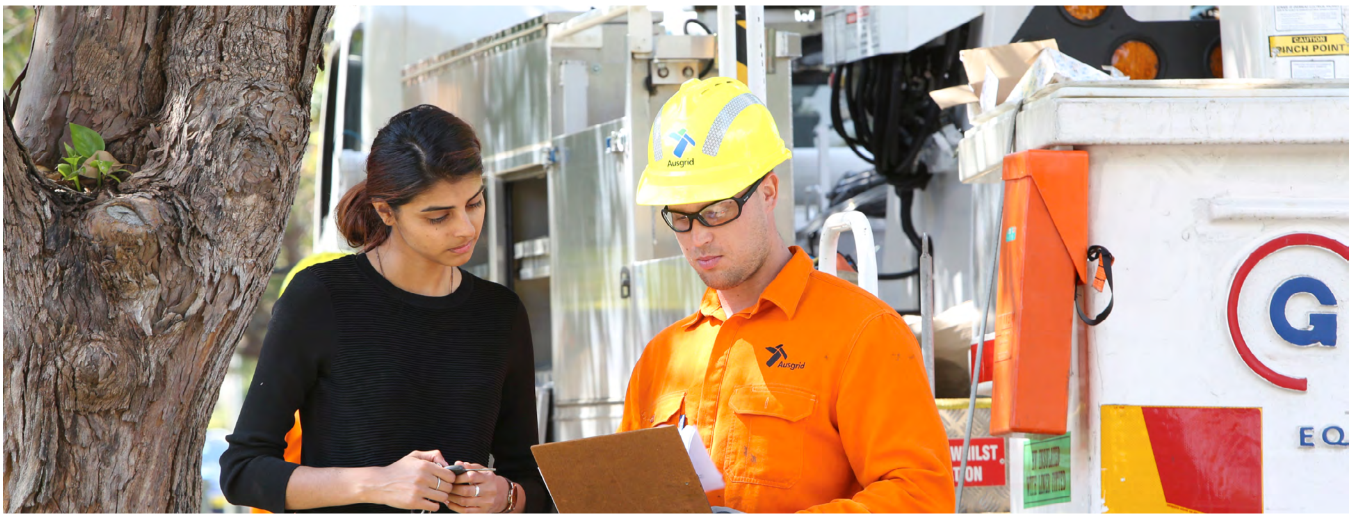
As metering technology has improved, we have implemented several pricing reforms to make our residential and small business tariffs more cost-reflective and give our customers more power to influence their bills. In 2003, we introduced TOU pricing for small customers with interval ready meters. These prices have a range of 'charging windows', so customers pay a higher rate for energy used during the periods of peak demand on our network. In 2019, we introduced demand pricing for new residential and small business customers with smart meters. These tariffs apply to a customer's metered peak demand that occurs over a month and within the peak period window.

If passed on by their retailer, our TOU and demand tariffs provide price signals to customers about how the timing of their energy use influences our network costs, and allow customers to lower their bills by shifting some of their energy use to when network demand is low. Importantly, if many customers respond to these price signals, these tariffs also help us control the growth in our network costs, reducing the overall costs of providing the community with network services.

Going forward for the 2024-29 period, we are proposing to simplify the structure of our cost reflective network tariffs. The goal of these simpler tariff structures includes to encourage more retailers to reflect these cost reflective price signals into retail tariff structures. Retailers may also respond in other ways, such as through 'prices-for-devices' pricing (explained elsewhere in this paper). We expect different retailers to respond in different ways providing our end customers with choice on how they pay for their energy.

Almost half a million residential and small business customers are on our TOU tariffs, and more than 280,000 are on demand tariffs. This is nearly a third of all our residential customers and more than half of all our small business customers.

For large commercial and industrial customers, our network prices are typically itemised on their bill so they can see the contribution of our network prices to their overall electricity costs and are better able to respond to their price signals. Our existing tariffs for these customers include capacity charges, which are applied to the highest peak demand that occurs over 12 months that falls within the peak period window.



2.3 Stakeholder consultation

In this section, we provide an overview of our engagement on pricing reforms to date. What we are hearing through our engagement, and how we are proposing to respond, is included in the discussion of our proposed reforms and tariff innovation in **Sections 3** and **4**.

Pricing Working Group

We continue to work closely with PWG to develop our proposed pricing reforms. The group's members include a range of customer and electricity industry advocates, as well as energy retailers and aggregators. Ausgrid has met with the PWG 15 times in the last year and discussed a wide range of topics relevant to the changes and opportunities facing the energy sector, and how our tariff structures and policies could be reformed to respond to these trends and provide better outcomes for our customers.

For example, the diverse members of the group have provided their perspectives on our pricing principles, and the options for and trade-offs involved in introducing and designing export pricing, changing our charging windows and our controlled load tariffs, streamlining our residential and business tariffs, reforming our policies for assigning customers to these tariffs, and introducing EV charging tariffs. Representatives from the AER and the NSW Government also attended most of the group's meetings, to provide comments and observe. We greatly appreciate each member's insights, contributions and assistance in developing our initial pricing reform proposals.

Our September 2022 PWG meeting focused on our proposal for embedded network tariffs. The meeting was attended by embedded network operators, Energy & Water Ombudsman of NSW, Australian Energy Market Commission (AEMC), and NSW Government. As a result of this meeting we received several submissions on our embedded network proposal, and this feedback is summarised in **Section 4.2**.

In our November 2022 PWG meeting we presented our export tariff and utility scale storage proposals. We thank PWG for their insight and feedback as we have developed these proposals.

Voice of Community Panel

To help us understand the experiences and perspectives of our residential customers, we have established a Voice of Community Panel. The panel includes 45 randomly selected members of the public who represent the diverse range of households our network serves across the Hunter, the Central Coast and Greater Sydney.

The feedback we have received from the panel is helping us to test whether our proposed pricing reforms reflect our customers' expectations of fairness and value for money. It is also helping us to gauge the extent to which customer behaviour could be influenced by price signals and pricing reforms that aim to optimise electricity supply and demand, balancing time of use, time of export, and reliability.

In the Town Hall meeting on 15 October 2022 we heard further feedback from the community on our export tariff proposal. Stakeholders emphasised that more customer education was required, particularly on how the export tariffs contribute to their cost. This includes explaining that it is unlikely customers would be charged to export (by their retailer). Rather, it is much more likely that customers will experience export pricing by receiving a slightly lower retail feed-in tariff (or slightly higher feed-in tariff depending on the time of export). They are also being rewarded for shifting their usage and smoothing out load on the grid.

At the VoC meeting on 21 October 2023 we presented our customer export tariff factsheet for feedback and comment (**Attachment 8.14**). Customers wanted the factsheet to be simpler, clearer and describe how customers could act to benefit (or reduce the impacts) from the tariff. The factsheet has been amended to allow for this feedback, including shortening it to two pages in length and reducing the number of bill impact case studies.

Large and medium business customers interviews

To better understand the perspectives of our large commercial and industrial customers, we interviewed representatives from several large businesses during March and again in September, 2022. In these interviews we found support for the proposed changes to the tariff charging windows and component structures, and for a price trajectory that is even across the 2024-29 regulatory period. We also held two forums for large customers in May 2022, to get their input and test our thinking on reforms, such as moving the peak period to later in the day and combining the existing shoulder and off-peak charging windows into a new off-peak window.

Small business interviews

In September 2022, we visited several small businesses in Lakemba, Cessnock, and Tuggerah and asked them for their views on our proposed pricing reforms. These interviews established that small businesses did not expect to be impacted greatly by our charging window or export tariff reforms. However, some small businesses seek a closer alignment of retail prices and charging components across residential and business tariffs.

Retailers and aggregators

During 2022 we invited retailers to 1 to 1 discussions on our reset, to attend PWG meetings and two retailer forums. Unfortunately, there wasn't a strong interest in 1 to 1 discussions on the reset, and PWG meetings were not regularly attended by retailer representatives. Pleasingly we had more than 40 attendees at both retailer forum meetings to discuss our proposed pricing reforms. Overall, the feedback we received was relatively limited. We did receive one submission from an energy retailer - Red Energy - which raised a number of concerns with our proposed reforms. We have responded to this feedback in Section 4.

We are working with aggregators to trial innovative tariffs. Most recently, we have partnered with Reposit Power to develop and demonstrate dynamic network tariff models as part of Project Edith (see **Section 3.3**). In March and November 2022, we hosted roundtable discussions with representatives from more than 20 retailers and aggregators to discuss the potential of more dynamic network tariffs. We have also received valuable feedback on how we could make it easier for retailers to engage with our tariffs and pass our price signals on to our customers.

Pricing Directions Paper

We released a Pricing Directions Paper in early September 2022 which contained our proposed pricing reforms for the 2024-29 period. We have consulted extensively with our stakeholders, including our customers, retailers, industry and consumer associations, and our regulator, the AER. The consultation on our Pricing Directions Paper received a total of 18 submissions from the following organisations:

- Firm Power
- Compliance Quarter
- Uniting
- Shopping Centre Council of Australia
- Electric Vehicle Council
- NSW Caravan & Camping Industry Association
- Shell Energy
- Origin Energy
- Red Energy/Lumo
- Energylocals
- GoEvie
- Northern Beaches Council
- Willoughby Council
- City of Sydney
- Inner West Council
- City of Newcastle
- Public Interest Advocacy Centre (**PIAC**)
- Total Environment Centre (**TEC**)

The feedback we have received through this process is included throughout this revised TSS Explanatory Statement. We have also included the amendments we have made to our proposal in response to this feedback.

2.4 Our pricing principles

We need to continue reforming our pricing, to meet the challenges and capture the opportunities facing the energy sector and our customers. The next regulatory period is expected to include significant changes in the way customers use our network as a result of CER uptake and electric vehicle charging. However, our proposal positions us and our customers well to manage these changes and to adapt to a range of futures. We have developed a set of reforms to implement in the 2024-29 period, and will continue to undertake pricing innovation to inform further reforms in future periods.

Our TSS provides details of how our proposed prices comply with the National Electricity Rule (**NER**) pricing principles. To provide further strategic direction to our reforms, we have developed a set of Ausgrid pricing principles in consultation with our PWG. We consider our pricing reforms for 2024-29 effectively balance these three principles:

1. **Efficiency**: our prices should reflect the overall efficient costs of operating the distribution network, and the costs associated with providing different network services at different times of the day and year. Efficient cost-reflective tariffs can signal to customers the costs of distributing electricity, enabling customers to decide whether the benefits they get from the electricity (consumed or self-generated) outweigh the costs.

2. **Flexibility**: our prices should reward customers for being flexible in when and how they use energy. Prices that encourage customers to consume energy at times of low network demand and export energy at times of peak network demand can improve the overall utilisation of the grid. This can reduce the need to augment the network and limit network charge increases for everyone in the long term. It also supports customer choice, facilitates innovation, and creates win-win outcomes across customer segments. In addition, our approach to price setting should be technology-neutral to promote innovation and remain relevant as technology evolves.

3. **Fairness**: our prices should recover our costs in a way that is fair and equitable to all customers. For example, they should not create an unfair burden on customers who have less ability to control their network charges, such as those renting and living in apartments, who may be unable to invest in CER, such as rooftop solar and battery storage systems. We should also consider customer impacts, and significant change should be supported by complementary measures to minimise these impacts if necessary.

Our Pricing Directions Paper consultation asked stakeholders for their views on our pricing principles. Northern Beaches, Newcastle and Willoughby Councils supported the proposed pricing principles. Northern Beaches and Willoughby Councils said that further information on how the approach will be implemented to ensure the proposed pricing is fair and equitable and does not discriminate between customers would be valued. We have provided further information on how we set prices in chapter 3 of our TSS compliance paper.

PIAC said that it considers fairness to be best expressed as an objective, rather than a pricing principle. We consider fairness to be a fundamental guiding consideration which is best expressed as a principle, rather than a destination (or objective) of itself. Further, PIAC indicated that flexibility should not imply that Ausgrid is seeking to provide retailers with flexibility in the tariffs they are exposed to. We generally agree, in the sense that retailers should only have very limited flexibility to move a customer to a less cost-reflective network pricing structure. PIAC supports rewarding customers for being flexible in how and when they use energy, where they are able to choose to do so. We agree, on the condition that this flexibility is beneficial for both the customer and the network.

We have found it valuable to have a set of pricing principles developed in consultation with our PWG to guide our pricing reforms. We also recognise the importance of our proposed reforms being consistent with the pricing principles established in the NER. **Table 2** explains how our pricing principles align with the NER pricing principles.

Table 2: Alignment of our pricing principles with NER pricing principles[3]

Our pricing principles	Alignment to NER pricing principles	Rationale
Efficiency	NER, clause 6.18.5(e) – stand alone and avoidable cost principle	Efficient tariffs avoid cross-subsidies between groups of customers by recovering revenue no higher than the standalone cost, and no lower than the avoidable cost, of serving that tariff class of customers. Cross-subsidies reduce allocative efficiency leading to unnecessary additional cost.
	NER, clause 6.18.5(f) – long run marginal cost principle	Efficient tariffs are based on the long run marginal cost (**LRMC**) of providing the service to customers assigned to that tariff. This helps ensure we only make investments when customers value the product of that investment.
	NER, clause 6.18.5(g) – total efficient cost and minimising distortions principle	Efficient tariffs recover residual costs in a way which minimises the distortions to LRMC-based price signals.
Flexibility	NER, clause 6.18.5(f) – long run marginal cost principle	Tariffs (and rewards) that signal LRMC during peak times appropriately encourages customers to be flexible in when and how they use energy.
	NER, clause 6.18.5(i) – customer understandability principle	The NER now recognises that retailers may incorporate our network tariff structures directly or indirectly into their retail offerings (e.g. through 'prices-for-devices' tariffs). Offering a range of cost reflective tariffs (TOU or demand) ensures customers always have access to an option they can easily understand.
Fairness	NER, clause 6.18.5(e) – standalone and avoidable cost principle	Fair tariffs avoid cross-subsidies between groups of customers by recovering revenue no higher than the stand alone cost, and no lower than the avoidable cost, of serving that tariff class of customers. Cross-subsidies are unfair because it means one group of customers are paying the costs caused by another group of customers.
	NER, clause 6.18.5(h) – customer impact principle	Fair tariffs take into account the impact on customers from tariff changes, and may include transitional measures or enable customer choice, where desirable. Fair tariffs also take into account customers' ability to respond to tariff signals.
	NER, clause 6.18.5(i) – customer understandability principle	Fairness means at least one tariff option is always available that is reasonably capable of being understood by customers, if reflected directly into retail tariff structures.
	NER, clause 6.18.5(g) – total efficient cost and minimising distortions principle	Fair tariffs are ones where all customers contribute to the residual costs of funding the network and where sub-sets of customers cannot easily avoid contributing to these costs, which would shift the cost burden onto other customers.

3 There is also a general NER pricing principle that states tariffs must be compliant with the Rules and any applicable regulatory instruments, such as jurisdictional requirements. NER, clause 6.18.5(j) – Applicable regulatory instruments compliance principle.

2.5 Energy affordability and bill impacts

After a period when our customers saw their bills go down, a range of factors are now putting upward pressure on the costs of supplying electricity, and thus on its affordability for our customers. These factors are largely outside of Ausgrid's control or affect the non-network components of electricity bills. For example:

- **High interest rates** and higher inflation are increasing our network costs, as well as the overall cost of energy supply, while also increasing our customers' cost of living;
- **Disruptions in the energy supply chain** due to gas shortages and an aging fleet of coal fired power stations are driving up the generation component of bills; and
- **Significant investments** in transmission infrastructure are expected to increase the transmission component of bills.

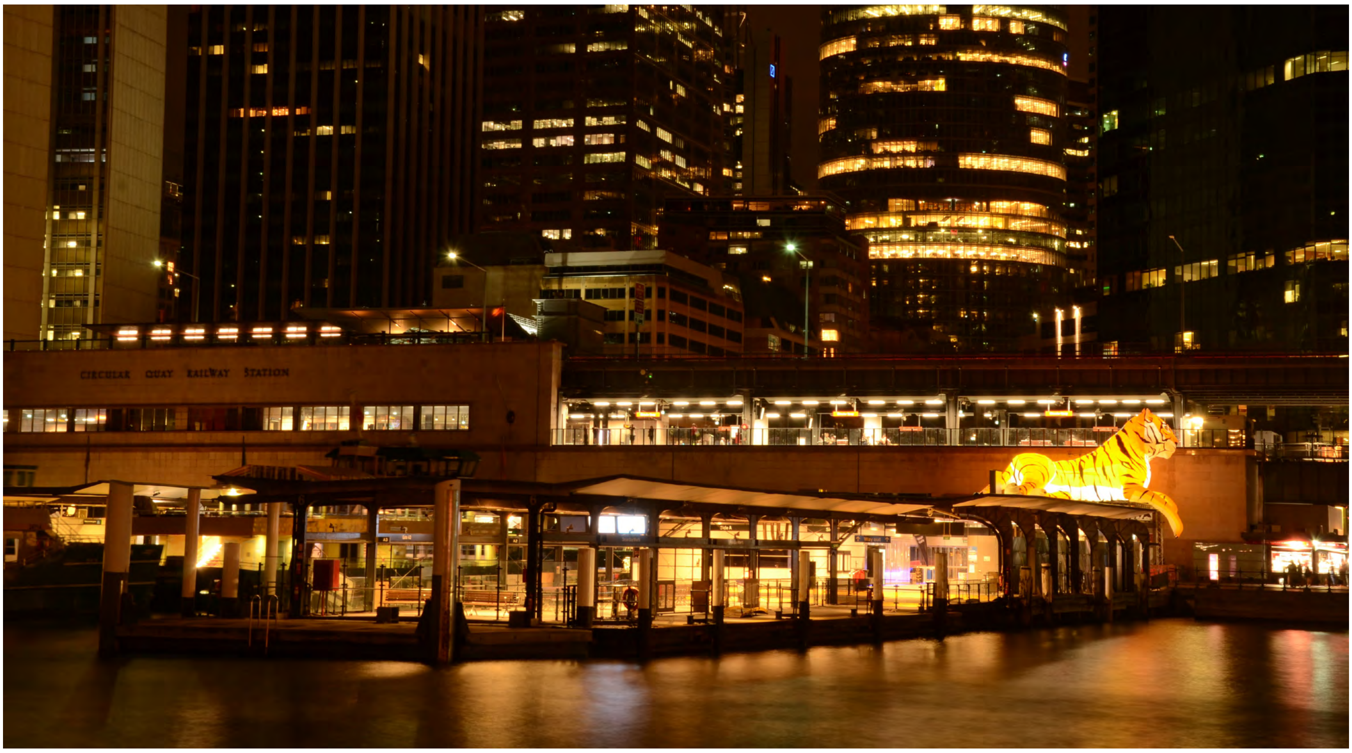
As explained in **Sections 3** and **4**, in response to the changes and opportunities ahead for the energy sector, and to what we are hearing in our engagement with our customers and communities, we are proposing a number of key changes to reform our standard tariff offerings for the 2024-29 period. Many of our proposed pricing reforms also aim to support an affordable transition by giving our customers choice and control over their energy services and bills.

For example, our tariff assignment policy moves customers (with capable metering) to demand tariffs with the option to opt-out to TOU tariffs. Our revised 2024-29 Regulatory Proposal also sets out a range of responses to ensure customers pay no more than necessary for our network services, and facilitates an affordable transition to net zero.

In an environment of energy affordability challenges, we aim to provide a clear indication of the impacts of our proposal to the network component of customer bills. The bill impact analysis supporting this explanatory statement is based on an estimate of total network charges for the 2024-25 year. It includes our proposed distribution and transmission revenues, and an estimate of the Transgrid and NSW Climate Change Fund pass through recoveries reflected in our network prices. We have also included the NSW Roadmap scheme recoveries and we note these costs were not included in the network bill impacts in our initial Proposal.

The full details of the bill impacts (by tariff) are included in **Attachment 8.3**. We have also included the customer network bill impacts for each of the main pricing reforms within the relevant chapter of this explanatory paper:

- Introducing export pricing for residential and small business customers (**Section 4.1**);
- Introducing tariffs for embedded network operators (**Section 4.2**);
- Streamlining our existing tariff offerings (**Section 4.3**); and
- Simplifying and updating the charging windows for our existing tariffs (**Section 4.4**).



We are responding to challenges and seizing opportunities

The energy sector – and energy customers – around the world are experiencing a period of profound change. The impacts of climate change – and the importance of transitioning to net zero emissions – are more apparent than ever before. New ways of living and working are leading to new patterns of energy use and customers are expecting individualised and affordable, zero emissions energy solutions. These changes create new opportunities for customers to be rewarded for using energy more flexibly, improving the utilisation of the grid, and lowering the overall cost of the system.

In the 2024-29 period, we want to build on the pricing reforms we have already introduced to maximise the opportunities for retailers and other partners, such as aggregators, to reward customers for their flexible use of the grid. We also want to continue trialling innovative tariffs, for example to provide new incentives for customers to realise the shared value of rooftop solar, battery storage and EVs. This innovation is critical to help us prepare for the future, from a distribution network to distribution system operator and offer more dynamic network prices (see **Section 3.3**).

In developing our pricing reform and tariff innovation proposals for 2024-29, we need to respond to three main changes in our operating environment:

- New government policies to drive the transition to a net zero economy;
- Expected growth in our customers' uptake of CER – such as rooftop solar, battery storage and EVs – to support the transition to net zero as well as control their own energy costs; and
- Upward pressures on energy bills.

In this section, we outline how we see the role of the distribution network changing to facilitate these priorities, support the transition to net zero and enable greater customer choice.

3.1 New government policies to drive the transition to net zero

While Australia has been transitioning towards a cleaner and more sustainable energy system for some time, the pace and urgency of change is picking up. Federal and state governments are implementing policies that commit to net zero by 2050 and facilitate the electrification of the economy needed to achieve this ambition.

Electricity Infrastructure Roadmap

The NSW Government's Electricity Infrastructure Roadmap (Roadmap) aims to deliver significantly more renewable generation capacity by 2030. It includes projects to provide 12 GW of renewable generation capacity and 2 GW of large-scale storage, which will be located in Renewable Energy Zones across NSW.

The government requires Ausgrid and the other NSW distributors (Endeavour Energy and Essential Energy) to pass through a range of costs associated with implementing the Roadmap to our customers from 1 July 2023. We understand that we are to include these in our prices as two new jurisdictional schemes; one scheme will pass through costs known as 'contribution determinations'. The other scheme will pass through costs of administering exemptions for entities from paying Roadmap costs, as nominated by NSW Government.

Electricity Supply and Reliability Check Up

Following the 2023 NSW State Election, the NSW Government confirmed its commitment to the Roadmap and decarbonisation of the electricity sector as part of its Net Zero by 2050 target. In mid-2023, the government commissioned an independent check-up of NSW energy policy settings. As part of the review the consulting firm Marsden Jacobs produced a report with 54 recommendations which covered a range of topics such as the closure timing of Eraring Power Station, Renewable Energy Zone implementation, and recovery of Roadmap scheme costs from consumers.

The NSW Government has accepted most of the recommendations of the check up report. The exemptions framework for Roadmap costs will be reviewed and consideration given to including transmission connected businesses to reduce the burden on small customers. The NSW Government will also work with distribution businesses on principles for how best to recover Roadmap contributions through their network tariff structures. Ausgrid will engage with the NSW Government on the development of these principles and seek alignment on the treatment of Roadmap charges for NSW consumers.

Our Pricing Directions Paper consultation asked stakeholders how we should pass through Roadmap costs to our customers. PIAC said that Roadmap costs would be more appropriately recovered through Transgrid, or from the NSW Government budget. Where Roadmap scheme costs continue to be recovered by DNSPs, PIAC recommends that the wholesale energy related portion of scheme costs should be recovered through volumetric charges and that network-related costs be recovered via demand charges. The costs of new transmission should ideally be recovered from the new entrant generators.

Emissions reduction objective

On 19 May 2023, Energy Ministers agreed to amendments to the national energy laws to incorporate emissions reductions into the national energy objectives. The National Electricity Objective now makes reference to targets (as set by a participating jurisdiction) for reducing Australia's greenhouse gas emissions or that are likely to contribute to reducing Australia's greenhouse gas emissions.

Ausgrid's tariff reforms for the 2024-29 period encourage consumers to electrify their overall energy use, and in doing so support decarbonisation of the energy system. This includes tariff incentives for CER where load is used in the middle of the day and energy exports are produced in the evening.

Hydrogen Strategy

The NSW Hydrogen Strategy is expected to result in a significant number of green hydrogen electrolysers connecting to our network in the Hunter region. The strategy requires:

- Distributors like Ausgrid to provide these green hydrogen producers a 90% reduction off their network charges;
- Green hydrogen producers to be located in parts of the network where there is spare capacity; and
- Network or market operators to be able to direct the electrolyser to turn off during peak events, or in response to dynamic price signals.

Our Pricing Directions Paper consultation asked stakeholders how we should set prices for green hydrogen electrolysers. PIAC said that the decision to discount network tariffs for hydrogen producers is not consistent with Ausgrid's pricing principles, the NER network pricing principles, or the long-term interests of energy users. However, in the absence of a change to this policy, it said the 10% of network costs should be recovered via a fixed charge. An additional critical peak charge should apply to any demand triggering the need for network upgrades.

Ausgrid will incorporate the 90% network charge reduction into our individually calculated network tariffs to enable us to comply with the scheme regulations.[64]

64 NSW Electricity Supply (General) Amendment (Green Hydrogen Limitation) Regulation

Electric Vehicle Strategy

The NSW Government's 2021 Electric Vehicle Strategy provides incentives to increase uptake of EVs over the next four years. It includes $171 million to build a road network of ultra-fast charging stations. In October 2022 the NSW Government announced it is investing $39.4 million in the first round of Fast Charging Grants to co-fund 86 new fast and ultra-fast EV charging stations, each with four to 15 bays. The recipients are Ampol, BP, Evie Networks, Tesla, the NRMA and Zeus Renewables.

Network tariffs and EV charging

We expect significant growth in EV ownership in our network area over 2024-29 and beyond. The time of day when customers charge their vehicles will be crucial, in addition to the location where this occurs – for example, at home, at a public charging station, or in an area of the network with a lot of solar generation.

Given the potential rapid uptake in EV load, the AER's Draft Decision encouraged Ausgrid to consider tariffs for flexible loads with more targeted windows and sharper price signals, including through controlled load tariffs.

Price signals can play an important role in encouraging customers to charge their EVs at times when electricity is abundant. We note that an increasing number of retailers[65] are offering EV pricing products, and our cost-reflective network tariffs have a role to play in supporting these offerings. It's also important that our tariffs send efficient price signals about the different costs of charging EVs at different times, so this growth does not drive significant increases in our long run costs.

Residential EV charging

EV specific tariffs for households face a barrier as distribution networks do not have visibility of EV ownership. However our proposed cost reflective tariffs for the 2024 - 29 period incentivises EV charging to occur outside of peak periods, in particular:

- Our residential demand and TOU tariffs signal the higher costs of charging in the evening peak period and encourage charging outside peak times when network demand is low. Our proposed changes to the charging windows for these tariffs (**Section 4.4**) will strengthen these signals (without these changes we are more likely to incur new demand peaks).
- Similarly, our solar customers already have strong incentives to charge EVs during the day, using their own generation, to avoid all network (and retail) variable charges. Our proposed export tariffs (**Section 4.1**) and the combined shoulder and off-peak energy charge will add to these incentives.

65 Emodi, N.V.; Dwyer, S.; Nagrath, K.; Alabi, J. Electromobility in Australia: Tariff Design Structure and Consumer Preferences for Mobile Distributed Energy Storage. Sustainability 2022

We note that Ausgrid already allows small customer EV charging via its controlled load tariffs. This provides a cost effective option for EV owners who are willing to use a secondary circuit for their charging. We will continue to offer this option in the 2024-29 period.

In FY25 we will also continue to trial our residential flexible load tariff, which offers a critical peak price for EV charging and other load connected on a secondary circuit. This trial tariff is amended from the FY23 version which used an interruptible service to control EV charging. The feedback from our retailers has been that an interruptible service at the network's discretion is not the preferred means of managing EV charging. Load control was acceptable to some retailers but only if it was at the retailer's (not the network's) direction.

Public EV charging

New EV charging stations typically have a lower utilisation of the network and can therefore experience a higher cost per unit of energy than other customers on the same tariff. In September 2021, we engaged with PWG to test a proposal to introduce separate medium business tariffs for EV charging stations. The meeting was attended by the Electric Vehicle Council, the AER, NSW Government, and customer representatives. Most stakeholders indicated that Ausgrid should not embed cross subsidies in our pricing to overcome transitional technology challenges. However our proposed reform of raising the threshold at which capacity tariffs apply (**Section 4.3**) will go a long way in addressing the feedback from the EV industry.

We recognise that we may need further tariff reforms in the future, as the impact of EV charging increases. We are currently trialling a flexible load tariff for small business customers, which includes a critical peak price.

Stakeholder Feedback

Our Pricing Directions Paper consultation asked stakeholders for their views on whether we should introduce EV tariffs. Northern Beaches and Willoughby Councils do not support the introduction of EV specific tariffs as it may delay EV uptake in its community and delay its transition to net zero.

PWG raised the concern that some EV households in our network may not have cost reflective tariffs. We agree that this is possible as there is no trigger for an EV household to have a meter upgrade if it uses slow AC charging. However if the household decides to invest in fast charging (with a wall charger or three phase supply) they are likely to have a meter upgrade and receive demand tariffs. We propose to engage with EV vendors and retailers on this question, to inform them and our customers of the opportunities available under our tariff assignment policy for EV owners.

In its submission PIAC did not consider the proposed demand and TOU tariffs suitable for enabling efficient integration of EV home charging. It supports technology specific tariffs for EVs and EV charging stations and also said that separate metering could support EV charging in apartment buildings. Ausgrid currently allows small customer EV charging to occur on its controlled load tariffs (which are separately metered), and we will continue this arrangement in the 2024-29 period. We consider that our proposed tariff structures provide suitable cost reflective incentives for EV charging for both households and public charging stations.

City of Newcastle said that Ausgrid should align its existing network tariffs with retailer EV pricing products, in particular the use of time-based price signals which will encourage EV smart chargers to be programmed when to operate. It also noted that lifting the assignment threshold to 100 MWh should go part way in addressing the feedback from the EV industry. It supports consideration of further pricing reforms in future, as the impact of EV charging increases.

GoEvie responded that Ausgrid should introduce a specific tariff for the EV public fast charging industry. The submission says that such a tariff would not create a cross-subsidy as EV charging structure provides network benefits such as increased network utilisation and stability, more solar soaking load, and network support via load control. It also said that residential and small business charges should be more closely aligned.

We believe that our proposed amendments to our tariff assignment policy for medium businesses (**Section 4.3**) will provide an appropriate balance between fairness and the need to reflect cost reflective price signals.

3.2 Becoming a Distribution System Operator

Energy Security Board Reforms

The Energy Security Board (**ESB**) was tasked with developing reforms to the design of the NEM to ensure it is fit-for-purpose in an energy system with high levels of renewables.

In August 2021, the ESB recommended market reforms to Energy Ministers, including to efficiently and safely integrate distribution-connected resources into markets at all levels. As part of this, the ESB recommended that the NEM becomes a two-sided market, in which customers' rooftop solar, batteries and other CER participate in the wholesale market through Virtual Power Plants (**VPPs**).

In its final advice to Ministers in 2021,[66] the ESB proposed that distribution network service providers assume the role of distribution system operators (**DSOs**) and work in co-ordination with AEMO to manage local and whole of system issues in highly distributed and renewable energy systems. As part of its advice to ministers, the ESB proposed that "support[ing] more dynamic network tariff designs that will result in automated responses from DER and flexible load" [67] should be one of the key responsibilities of the DSO.

In August 2023, AEMO's Electricity Statement of Opportunities highlighted the importance of customer participation, stating that "should these orchestrated consumer resources and demand reduction schemes occur to the scale projected, the reliability forecast is expected to improve considerably."[68]

Ausgrid's DSO vision

Ausgrid has taken up this challenge. We see our role as a DSO as dynamically managing network capacity and operating the network to maintain an efficient, safe, and reliable service while optimising value to our customers, the energy system and supporting the renewable energy transition. In addition to uplifting our ability to dynamically manage the network as energy flows become more complex and playing a larger role in supporting the end-to-end security of the system in partnership with AEMO, we are also evolving our network services to support two-sided markets.

Technology offers the opportunity to move beyond static and average network prices and accounting for differences in location and time. That is creating new opportunities for how we think about network pricing and share value with our customers.

However, sometimes our current network tariffs can distort market participation by over or under stating the cost of network use and not rewarding beneficial behaviour. In addition, static measures to manage network capacity, such as limits at the time of connection, can reduce efficient use of the network. We see our services evolving in two key ways to address this:

- Developing dynamic access and connection solutions that provide a range of options for customers in line with their individual needs (but still retaining cost reflective and efficient pricing principles); and
- Improving system affordability for all our customers through encouraging efficient two-way utilisation of the network through dynamic network pricing.

Importantly, we see the role of the DSO is to support customers to participate in local and wholesale markets as they evolve, not to run local energy markets. Similarly, the DSO's role is to support retailers and aggregators by providing a flexible and reliable network service that they can use to aggregate and orchestrate customer resources in commercial products for their customers.

66 ESB Post 2022 market design final advice to energy ministers Part B, p70 (released 26 August 2021). https://esb-post2025-market-design.aemc.gov.au/32572/1629945809-post-2025-market-design-final-advice-to-energy-ministers-part-b.pdf

67 Ibid p 70

68 2023 Electricity Statement of Opportunities, p95. https://aemo.com.au/-/

Ausgrid's DSO reforms and investments

In the 2024-29 period, we want to build on the pricing reforms we have already introduced to maximise the opportunities for retailers and other partners, such as aggregators, to reward customers for their flexible use of the grid. We also want to continue trialling innovative tariffs, for example to provide new incentives for customers to realise the shared value of rooftop solar, battery storage and EVs. This innovation is critical to help us prepare for the future, from a distribution network to DSO and offer more dynamic network prices (see **Section 3.3**).

Our 2024-29 regulatory proposal includes an overview of the activities we are planning on taking to support the net zero transition over the next regulatory period, including foundational investments in systems to enable more flexible connections and more dynamic pricing. In its response to the proposal, PIAC stated that it "supports this intent [of Ausgrid's DSO investments] and agrees that it reflects the strong preference from Ausgrid's consumers for Ausgrid to invest in more dynamic, flexible and 'future-focused' network solutions."

While the dynamic pricing structure offers greater flexibility to DNSPs and supports value for customers, there is diversity in customer participation. Customers are likely to range from those that are extremely involved, or 'active' in the market to those that are content with a static tariff structure. Therefore, in the future we need to have a range of tariff options for customers, depending on their preferences. It will continue to remain important that we cater for all customers, and to apply our pricing principles (fairness, efficiency and flexibility) to achieve this goal.

Our Pricing Directions Paper consultation asked stakeholders for their views on how we are using our tariffs to support the transition to net zero. Northern Beaches and Willoughby Councils responded that the proposed pricing reforms, particularly those that will help reduce bills to customers, improve customer benefits from their CER investments and reduce emissions. City of Newcastle said it supports implementation of dynamic access and connection solutions that improves system affordability for Ausgrid customers.

In its draft determination, the AER did not approve the $12.1 million proposal for DSO systems investments to prepare dynamic network services (including dynamic network pricing and dynamic operating envelopes) for scale, citing concern with the method used to calculate market benefits. Our revised proposal includes an update to the market benefits analysis, using the Customer Export Curtailment Value (CECV) as a measure of the time-value of energy, in line with the AER's advice. We are confident that this updated analysis supports approval of the DSO investments so that this important reform can continue development and demonstrate a model for efficiently facilitating market participation of orchestrated CER that others can follow.

The AER's draft determination also significantly reduced investment in our Enterprise Resource Planning (ERP) platform, which includes investment to modernise metering and billing capabilities. While an interim billing solution is being developed for Project Edith to progress to an on-market trial tariff, it is uncertain whether the existing systems will support scaled deployment with the complete capabilities required for retail billing. Approval of the ERP upgrade will provide a stronger foundation for continued pricing innovation to meet the changing needs of customers through the energy transition.

3.3 Leading pricing innovation

Our proposed tariff innovation and tariff trials for 2024-29 aim to improve our customers' opportunities to benefit from their CER investments, to share those benefits across our customers, and to build our capability to unlock new opportunities that will emerge from expected market changes over the coming years. Across the 2024-29 period, we propose to focus our tariff innovation on providing our customers and retailers with new choices and more opportunities to respond to incentives to efficiently utilise the network. Together with our proposed pricing reforms, this innovation improves our ability to facilitate and support the transition to net zero.

Ausgrid is committed to tariff innovation. We are continuously researching new ideas and ways for tariffs to better serve our customers. However, changing our tariffs can have a significant impact on our customers, our network and the broader energy system. For this reason, we take a staged approach to evolving our tariffs that generally involves:

1. **Concept development.** We research and develop new ideas and ways for tariffs to better serve our customers through desktop studies or small trials.

2. **Tariff trials.** The NER allows distribution networks like Ausgrid to add new tariffs each year if they do not recover more than 1% of our revenue each or 5% of our revenue combined. These are known as sub-threshold tariffs, or trial tariffs. This provision allows us to implement innovative tariffs alongside our regulated tariffs, testing our capabilities and customer interest.

3. **Pricing reform.** Ultimately the insights from our tariff trials and broader modelling informs the tariff reforms we include in our TSS proposal. Once approved by the AER, these tariffs become our standard tariff offerings. For example, in 2019 we introduced residential demand tariffs and residential TOU demand tariffs through our TSS proposal and approval process.

During the energy transition the focus of our tariff innovation will be to learn what customers and retailers want, understand what drives efficient network use, and test our capabilities to operate new tariffs.

Our Pricing Directions Paper consultation asked stakeholders for their views on how quickly we should introduce innovative tariffs. PIAC said that EV tariffs should be introduced at the earliest opportunity. Firm Power stated that Ausgrid should move quickly to introduce a standard tariff for large batteries. Our proposal for utility scale storage tariffs is presented in the earlier section.

Dynamic cost-reflective pricing trials

We are currently undertaking a trial, known as Project Edith, as a proof of concept and proof of capability that we can send dynamic network prices to customers (via aggregators) and that they can respond to them. Dynamic network prices allow customers, aggregators and virtual power plants to get more cost-reflective price signals that vary by forecast network use. This gives customers greater opportunities to trade on energy markets and enables price responsive network support.

In many ways, Project Edith reimagines the role and flexibility of network pricing. It is iteratively trialling new dynamic pricing approaches alongside dynamic operating envelopes. Recognising the range in customer needs and the balance of efficiency and complexity, we are currently testing two implementations of dynamic pricing:

1. A rule-based pricing algorithm using weather inputs to select the most appropriate prices from pre-defined levels, based on long-run marginal cost.
2. A short-run-marginal-cost solver to calculate the prices needed to keep forecast local network use within forecast capacity at each location.

The weather-based inputs in method 1 act as a simple proxy for network congestion. Method 2 forecasts network congestion directly and uses predictions of price elasticity of customer demand and generation to calculate the ability of customer response to manage congestion. Both methods include negative prices to reward customers for network use that helps to reduce congestion.

The resulting prices more accurately reflect the state of the network at each time and place, allowing customers to more efficiently access market value when there is available network capacity and to be rewarded for flexibility when capacity is exhausted, helping to avoid unnecessary augmentation and reduce network costs for all customers.

Project Edith is currently a small-scale trial with a single aggregator partner representing less than 300 participating customers. Having successfully engaged stakeholders to consider Project Edith as a viable option for facilitating two-sided markets, we are now preparing to onboard additional aggregators and retailers to expand the trial to 1000 customers and continue to demonstrate and validate the dynamic pricing concept.

Our Pricing Directions Paper consultation asked stakeholders for their views on how we can continue to build and test dynamic network pricing through the 2024-29 period. In its submission PIAC supported Ausgrid building its capability to effectively implement dynamic network pricing in the 2024-2029 period, including through tariff trials. City of Newcastle supported the continued use and implementation of Project Edith.

Lessons from current tariff trials

Ausgrid currently has five sub-threshold tariffs:

1. Residential two-way tariff
2. Flexible load tariff
3. Community battery tariff
4. Super off-peak tariff
5. Standalone power system tariff

The residential two-way tariff has helped Ausgrid design the export tariff included in our TSS. The key lessons have been:

- Energy based basic export limit (BEL) - in developing our trial tariff, we found our billing system will not allow us to pair a demand measure BEL (e.g. 3 kW) with a usage charge (e.g. c/kWh exported). This led to our inclining block energy based BEL and usage charge, which we prefer given solar feed-in tariffs are predominately energy based.
- Charging windows need to reflect network conditions – the export charging windows for the trial tariff are based on our current summer peak window but applied all days, year-round. We have found that this does not reflect our network costs where most of our export customers are located. We have refined our export charging windows to reduce how often we reward exports when exports are driving voltage constraints.
- Residual costs in export tariffs distort customer decisions - the trial tariff artificially increased the peak usage charge and the export reward, by recovering additional residual costs from consumption and refunding those residual costs in the export reward. This approach has made our trial tariff lucrative for customers investing in batteries and driven additional cycling of batteries in response to our tariff. This has informed our decision to base export charges and rewards on the LRMC of exports on our network.

Our flexible load tariff has been developed from an earlier version launched in FY23. This earlier version used controlled load to manage residential EV charging load. However, the feedback from our retailers has been that network interruptibility is not a preferred way of managing customer EV charging. Load control was acceptable to some retailers but only if it was at the retailer's (not the network's) direction. We have therefore amended this tariff to be a critical peak price in FY24. We have also introduced a small business version of this tariff.

Our community battery tariff applied to its first customers in September 2023. We will continue to gather data from the operation of community batteries. This will help understand how small scale storage can balance energy use across local neighborhoods by responding to reward and charge price signals.

New trial tariffs

For 2024-25 Ausgrid proposes the following sub-threshold tariffs:

1. **Local use of system (LUOS) tariff –** to provide an incentive for customers located near a community battery to participate in a retailer offer. We are currently working with retailers on the design of this tariff, and it may feature a similar structure to the existing standalone power system trial tariff. We will publish further details in April for the FY25 network price change submission.

2. **Flexible load tariff –** we will continue to offer a flexible load tariff where instead of interrupting customer supply we will apply a critical peak price. This is available to residential customers on a secondary circuit and to small business customers as a primary tariff.

Proposed pricing reforms for 2024-29

In response to the changes and opportunities ahead for the energy sector, and to what we are hearing in our engagement with our customers and communities, we are reforming our standard tariff offerings for the 2024-29 period.

We are proposing six main changes:

- **Introducing export pricing for residential and small business customers after a one-year transition period**, to reflect the increasing costs to support CER customers' exports and provide an incentive for CER customers to self-consume or time their exports to minimise these costs and maximise the benefits they receive;
- **Introducing tariffs for embedded network operators** to ensure they make a fair contribution to residual costs, over a five-year transition period;
- **Streamlining our existing tariff offerings and tariff assignment policies for our customers** to make it easier for retailers and market aggregators to respond to or pass through our price signals to our customers;
- **Simplifying and updating the charging windows for our demand, capacity and TOU tariffs** to make it easier for retailers to pass through our price signals to customers, and ensure customers know when demand on our network is highest;
- **Introducing pricing for utility scale storage facilities**, to enable directly connected batteries and other energy storage facilities to connect to our network and create a level playing field for projects located in the distribution network; and
- **Updating our controlled load tariffs for residential and small business customers** to reflect changes in the times of day when demand on our network is lowest, and allow our controlled load customers to operate their hot water systems during the day when solar energy production is highest.

We think our proposed reforms would make our tariffs more efficient, flexible, fair, and sufficiently cater for the anticipated electrification of transport. The sections below discuss each of the changes we are proposing in more detail and set out the questions we seek comments on.

In these sections, we explain our rationale with reference to our three pricing principles – efficiency, flexibility and fairness. We also link our rationale back to the NER requirements by providing a footnote reference to the relevant NER pricing principles throughout our reasoning.

4.1 Introducing export pricing

Background

In 2021, the AEMC changed the NER to recognise that exports onto distribution networks can reach or exceed the intrinsic hosting capacity and drive network costs. However, network providers were not able to signal the cost of providing export services to those that use this service. To address this, the NER now allow distribution networks to charge and provide rewards for exports.

This reform to the Rules stemmed from the Distributed Energy Integration Program (**DEIP**) Access & Pricing Workstream, co-ordinated by ARENA, which was a highly collaborative process between customer representatives, environmental representatives, market bodies, industry and government. It adopted a multi-stage process that started with establishing a user-centred vision and principles to guide CER integration reform, identified a range of CER access and pricing options, then analysed those options. This process was undertaken through a series of workshops, reports and discussions involving many stakeholders. The DEIP Access & Pricing Workstream resulted in a consumer group, environmental group and distributors proposing rule changes to the AEMC which created the DER Access, Pricing and Incentives rule change. This rule change made several changes to the rules – notably the removal of the ban on export charges and enablement of credits, to have two-way pricing. Our TSS proposal implements this reform.

When the volume of energy exported to the grid at the same time exceeds the intrinsic hosting capacity, customers with solar will experience reduced solar generation and export reliability. This is because when the network exceeds its intrinsic hosting ability, the voltage level exceeds the standards. This causes solar customers' inverters to curtail energy production, reducing their ability to export or self-consume solar energy until voltage returns to within the prescribed range. Alternatively, if we spend more money to manage these voltage swings by augmenting the capacity of our network so we can accept more exports, all customers may face higher prices.

We think the introduction of export pricing aligns with our pricing principles:

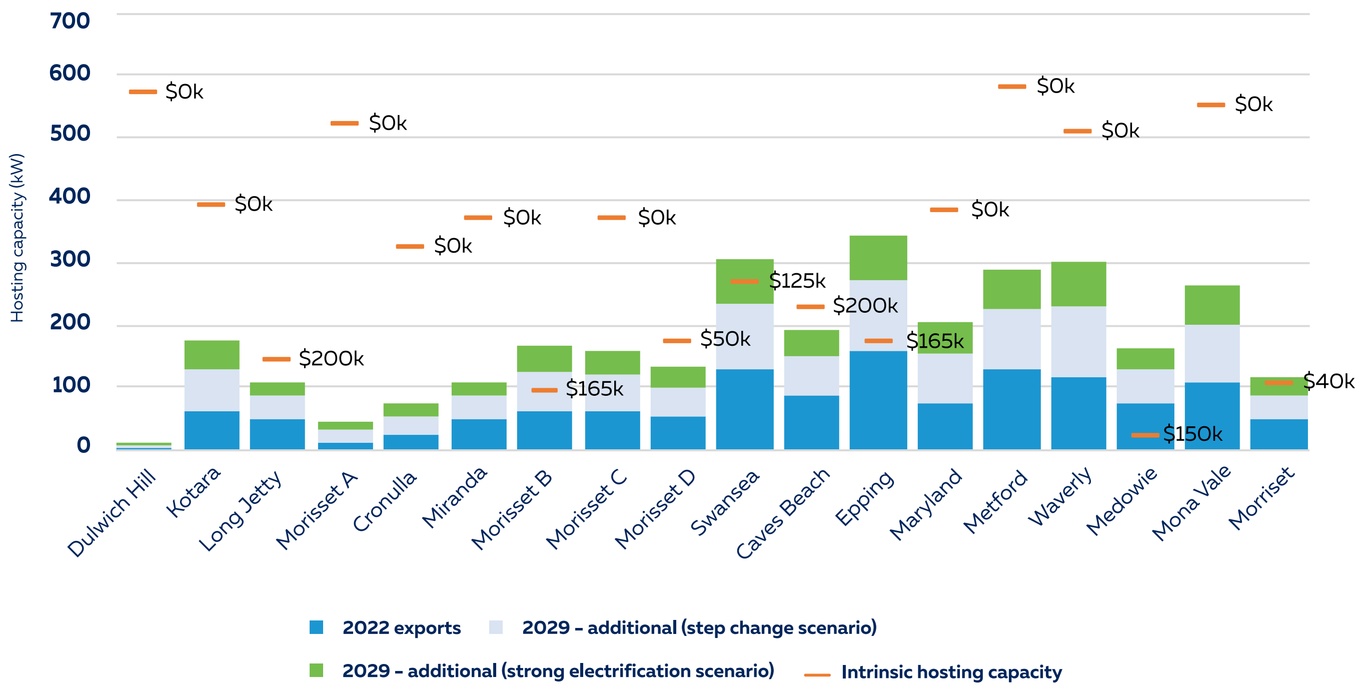
- **Export charges create more efficient outcomes.** By signalling the costs and benefits of exports, customers can make more informed decisions about the sizing of their CER like rooftop solar, when it is optimal to self-consume their generation, or invest in energy storage;[4]
- **Export charges can reward flexibility.** The flexibility principle builds on the efficiency principle as it involves sending efficient price signals that allow customers that can be flexible to save money. Customers who can self-consume their generation or move when they export (e.g. by installing western facing rooftop solar or batteries) will share in the benefits this provides our network through lower bills;[5] and
- **Export charges can create a fairer outcome.** Our fairness principle means our network charges minimise situations where some of our customers are paying more so we can supply other customers.[6] When we were able to accept all customers' exports without any additional network investment it was fair that customers exporting did not pay for exporting. However, as we incur costs to accept exports we are creating a situation where customers are receiving a service for less than it costs us to provide it.[7]

When assessing whether to introduce export pricing, we have considered the impact of CER on the grid now and into the future. Over the last few years we have made significant improvements in how we manage network voltage, including lowering the average voltage across much of our network. This creates some additional capacity for us to enable customer exports.

However, in parts of our network, we are reaching or have started to exceed the limits of the exports we can accept without augmenting the network (also known as the intrinsic hosting capacity). The following figure demonstrates how different export forecasts trigger CER investment, both in the next regulatory period and beyond. Network augmentation triggers include upgrades to overhead low voltage conductors, installation of new underground cables, installation of new distribution substations and network re-arrangement. If AEMO's Step Change scenario for CER uptake proves to be reasonably accurate, between 2024-29 we expect intrinsic hosting capacity to be exhausted in parts of the network. Across 16 sampled locations in the LV network, half are expected to require investment by 2050 under the Australian Energy Market Operator (AEMO) step change scenario. We provided the details of this intrinsic hosting analysis in our January 2023 proposal as **Attachment 8.5**. This analysis shows it would be prudent to start sending our customers price signals about the costs and benefits their exports can have on grid costs.[8]

4 NER, clause 6.18.5(f) – Long run marginal cost principle
5 NER, clause 6.18.5(f) – Long run marginal cost principle
6 NER, clause 6.18.5(g) – Total efficient cost and minimising distortions principle
7 NER, clause 6.18.5(g) – Long run marginal cost principle
8 NER, clause 6.18.5(g) – Total efficient cost principle

Figure 1: Investment triggers to 2050 for 16 sample locations in the low voltage network (the dollars shown are the required investment real $, FY24)



Our proposed export tariffs

We propose to introduce an opt-in export tariff from 1 July 2024 and then move to a default assignment a year later. The export tariff would:

- **Have a Basic Export Level[9] (BEL) over the 2024-29 period.** Customers would not be charged for energy exports below this threshold. Our analysis indicates that 2,500 kWh per year is the appropriate level for the BEL for exports within the 10am to 3pm charging window. For practical reasons, it is important to align the duration the BEL is measured over with our billing period.[10] This ensures there is no need for ex-post adjustments;
- **Include both a charge component and a reward component.** Customers receive a payment or credit for the volume they export during the peak demand period (and no threshold applies to reward exports)
  - **Export charge component** of 1.17 cents per kWh (ex GST, FY24 $) of energy exported above the BEL between 10am and 3pm. This period is when total exports from our customers' rooftop solar systems are highest, and therefore when these exports are most likely to drive network costs;[11]
  - **Export reward component** of 2.33 cents per kWh (ex GST, FY24 $) of energy exported between 4pm and 9pm and in the peak period. This period is when total demand on our network is highest, and therefore when customer exports provide most benefit to the network;[12]
- **Applies to new and existing[13] residential and small business customers** on cost-reflective tariffs, regardless of where they connect to the network, and when they invest in CER. We believe this approach treats customers equally;
- **Be initially available on an opt-in basis only.** From 1 July 2024, only customers who choose to opt-in would receive the tariff as part of the first year transition period;[14] and
- **Become our default tariff in the second year of the period.** From 1 July 2025, all residential and small business customers who have an approved network connection with export capability will be automatically assigned to the tariff.[15]

We have provided a worked example and bill impact case studies in our export tariff factsheet (**Attachment 8.14**).

9 Required under the new export tariff transitional rule. NER, clause 11.141.12

10 Formally, we propose our BEL to be calculated as 6.85 kWh per number of days in the billing period. For example, a 30 day billing period has a BEL of 205.5 kWh.

11 NER, clause 6.18.5(f) – Long run marginal cost principle

12 NER, clause 6.18.5(f) – Long run marginal cost principle

13 The export tariff transitional rule defines an existing CER customer as one that was connected as of 19 August 2021.

14 NER, clause 6.18.5(h) – Customer impact principle

15 Under the new export tariff transitional rule, an existing CER customer cannot be assigned to an export tariff until after 30 June 2025. NER, clause 11.141.11(a)

When combined with the proposed BEL and the proposed reward component, we estimate that the export charge will have a minimal impact on the bills of CER enabled customers over the 2024-29 period.[16] We think even at a low price level, now is an appropriate time to introduce export pricing. This enables our customers to become familiar with export pricing structures without incurring meaningful cost impacts for this component.[17] Export charges are likely to be a much smaller portion of the bill than consumption charges. Putting these structures in place from FY25 will prepare Ausgrid and customers for subsequent regulatory periods and the continued shift to a decentralised and decarbonised energy system.

Our proposed charge is set lower than the rebate and achieves an appropriate balance of reward and charge across our customers with and without rooftop solar. Customers who export more energy are more likely to face a net charge, rather than reward. Our indicative estimates for FY26 show that our export/reward tariff will result in $1.5 million less distribution revenue recovered from non-solar customers than would be the case without our export pricing proposal.[18] This outcome was presented to our PWG in December 2022 and was a result of a scenario analysis that considered different charging windows and recovery of residual revenue. We may introduce a residual component in our future export tariffs but this currently does not form part of our proposal.

We do not propose to introduce export pricing for large commercial and industrial load customers in the 2024-29 period, other than for utility-scale battery customers as currently most of the CER exports to our network come from small customers. However, we may trial export pricing for large customers over this period, and these customers will be able to opt-in to these trials.

We note that our export pricing proposal may differ to the proposals of other NSW distributors. This is due to a number of reasons, including different CER penetration rates, customer usage profiles, and billing system capabilities.

16 NER, clause 6.18.5(h) – Customer impact principle
17 NER, clause 6.18.5(i) – Customer understandability principle
18 NER, clause 6.18.5(g) – Total efficient cost and minimising distortions principle

Why isn't our export reward price higher?

During our consultation, stakeholders asked why our proposed export reward isn't higher than the export charge. This feedback was triggered in part by an Ausgrid temporary trial tariff which has a large export reward component. Our pricing approach seeks to deliver fairness for customers with access to export-capable technology, such as rooftop solar, and customers that do not have this technology. In deciding what is fair, we have balanced the size of the reward for exporting customers, with the regulatory rules mandate that we give a free allowance for exporting electricity to the grid.

We want to ensure that we don't create a cross subsidy at the expense of customers who aren't export capable. This could occur if the export reward was higher than what we propose given our regulatory framework includes a revenue cap. We are also required to ensure LRMC is reflected in our prices and the LRMC values for these prices are very low.

Our TSS compliance paper also includes our basic export transition strategy and approach used to calculate the BEL and export LRMC.

Stakeholder feedback to the Pricing Directions Paper

Our Pricing Directions Paper consultation asked stakeholders about our proposal to introduce export pricing. In its submission, the TEC asked why the proposed reward component was not more generous for CER enabled customers. They suggested that the LRMC of consumption be used to determine the price for the reward component. We agree with this feedback and have moved the reward price from 1.85 to 2.33c/kWh which reflects the upper bound of our consumption LRMC. Our TSS compliance paper includes further information on how we calculate the LRMC of export services and the BEL. TEC also said that Ausgrid lacks a clear need for the introduction of export pricing. However, our analysis indicates that we will incur additional costs as customer export capacity increases, and this is reflected in a positive value for the export LRMC. We have provided further information on our export LRMC in our TSS.

City of Newcastle supported the proposed changes. The City of Sydney said that the proposed charge is unlikely to be sufficient for customers to invest in grid support solutions like west-facing solar panels or costly battery storage. It also suggested that the price signal may not be passed through by retailers, and if it was most customers would not know how to respond. At our council forum in September 2022, we also heard that the proposal is a good incentive for west facing panels and home storage, but the tariff cost impact is so negligible and obscure (behind retailer tariffs) that it may be ineffectual. However, in our large customer interviews, NSW Treasury (in its role of whole of government procurement) said that the proposed changes would impact the retail feed-in tariff that it receives across its portfolio of rooftop PV installations. We have considered this feedback and have decided to start the export reward period at 4pm, instead of 3pm. This will mean the rebate becomes a stronger price signal, is more likely to be passed through by retailers, and will encourage west facing solar investments and batteries.

Northern Beaches and Willoughby Councils supported the commencement of opt in from 1 July 2024, however, they also recommend that the mandatory roll-out is delayed for more than the proposed one-year interval to allow customers to be better prepared. Ausgrid has considered this feedback. A transition period would not provide any clear benefits to customers given the small impact the proposed changes will have on network bills (under current CER forecasts). Our export charge only applies above the free threshold and is lower than what was initially proposed in the Pricing Directions Paper. We consider this change suitably addresses stakeholders' concerns on the introduction of export pricing.

Inner West Council said that export tariffs will penalise solar owners who invest in good faith to cut their energy bills and do their part for the environment. It recommended that the reduction to feed-in tariffs should be accompanied by reductions in consumption charges for solar customers. Ausgrid's view is that the proposed export tariff will not create significant bill impacts for the majority of solar owners, on the assumption that future CER investment will not exceed the current forecasts. Our export tariff proposal provides bill saving opportunities for west facing solar panels and battery investments.

Our focus groups for culturally and linguistically diverse (**CALD**) stakeholders suggested that the proposed changes may be unfair for customers who had already invested in solar panels. We note that our export tariff becomes mandatory four years after the rule change was finalised. These stakeholders also considered that the proposal may be perceived as discouraging CER take up and customers should be informed early of these changes. At our Peak Group roundtable meeting we heard that if export tariffs are required to make a fair balance between solar and non-solar households, then the tariff must be mandatory. There may be a communication challenge if each network responds differently on export tariffs, and engagement with retailers was critical in passing through the price signal.

PIAC supported the proposal for the export tariff to be mandatory from 1 July 2025 and that it should not allow customer opt-outs. It also said that the BEL should be introduced on a more cost reflective basis. In particular, the tariff should be applied in network billing on a kilowatt (kW) basis, not as a kilowatt-hour (kWh) threshold. The reward should only be applied in locations where exports help avoid or delay network upgrades or reduce the need for load shedding. In response to the PIAC submission, we have balanced tariff simplicity and the cost of changing our billing systems with the potential efficiency benefit of billing based on kilowatts. We consider our proposed kWh export tariff sufficiently achieves the aim of charging the high export-capable customers more than those customers with only a small export capability. Therefore we consider it is a suitable pricing structure for our proposed export tariff. We are continuing to review our billing systems as we introduce more dynamic pricing signals over time, and if an efficient change to our systems could accommodate kW, we will engage further with stakeholders at that time.

Red Energy responded that the proposed export tariff will require IT changes, collateral changes and extensive training to their staff to be able to communicate the changes. It preferred that Ausgrid provide an opt-in export tariff that is consistently structured with other NSW networks for the 5-year period. We note in response that export pricing is being introduced across NSW and both Ausgrid and Essential Energy are proposing a mandatorily assigned export tariff in the next regulatory period. We also agree that the introduction of export tariffs will require an adequate retailer communication program.

Our engagement with PWG highlighted that introducing export pricing is a complex issue, which particularly concerns customers who have already invested in CER. The group suggested ways of improving our communication of the export tariff to customers, including the BEL. Some of the issues we explored were whether export prices should only be introduced for customers who have invested in CER, and whether the price signals provided should be on a locational basis, given different impacts of energy exports across different parts of our network.

PWG noted that the proportion of customers who have already invested in CER varies by location within our network area, and the intrinsic hosting ability of the network also varies by location. They suggested it may be more cost-reflective to apply the export tariff (including the level of the BEL) on a locational basis. While we agree there would be some benefits in introducing export pricing on a locational basis, we consider these are outweighed by the costs. In particular, we think it is more important to avoid the complexity of differentiated pricing for a relatively small component of the bills of our small customers, and to retain the simplicity of postage-stamp pricing for at least the 2024-29 period.

Our Voice of Community Panel recommended that recovering the costs associated with customers' exports by introducing a TOU export tariff takes into account network stability and cost. In particular, export services could be priced differently at different times of day, to reflect periods of peak demand (and peak exports). The panel also recommended we should allow CER customers to opt-in to this tariff initially, with a view to transitioning to all-in over the 2024-29 period.

In our engagement with our communities, we also discussed whether we should provide "grandfathering provisions", so that customers who invested in CER before the export was introduced are exempt from the tariff. Our Voice of Community Panel indicated a preference to avoid these provisions, and to treat all small customers in the same way. In line with this feedback, we propose to assign all residential and small business customers on demand and TOU tariffs to the export pricing structure from 1 July 2025.

Responding to stakeholder feedback

Our September 2022 Pricing Directions Paper discussed whether the export tariff should be mandatory or whether opt-out should be allowed. A key consideration for allowing opt-out is the impacts on other customers. For example, under an opt-out scenario, customers with large solar systems are more likely to opt-out to avoid charges.[19] To overcome this challenge, we considered providing a greater incentive for these customers to encourage them to remain on the export tariff. However, this would reduce the cost reflectivity of the export tariffs and put a burden on customers without solar.

We consulted on whether customers should be able to opt-out of the export tariff. At our September 2022 Voice of Community meeting, participants supported mandatory export tariffs if the introduction included a community education campaign. The need for customer communication was highlighted given the potential complexity of a new, two-way pricing structure. The Voice of Community support was also based on the following considerations:

- Rooftop PV systems can be paid back in 4-5 years and customers will have had four years notice of these changes;
- The export charge is a small amount based on current CER forecasts and it includes a free threshold;
- The export tariff will reduce their feed-in-tariff, rather than be a standalone charge; and
- Only larger systems will see the biggest change and they shouldn't be the ones to opt-out.

Given this feedback we think our proposed approach of introducing mandatory export tariffs from 1 July 2025 could be more effective if it includes a customer education campaign. We have published an export tariff factsheet (**Attachment 8.14**) with our revised TSS. It includes an export tariff worked example with case studies showing network bill impacts for different customer types. The factsheet was reviewed by our Voice of Community group at the October 2023 meeting. The factsheet has been amended to allow for this feedback, including clarifying how customers can benefit from the reward credit and shortening the document to two pages in length.

Other changes since the Pricing Directions Paper include increasing the export reward price by:

- Basing the reward on the upper limit of the LRMC of consumption services; and
- Starting the reward period at 4pm instead of 3pm.

Our analysis shows that moving the reward window to 4pm is more likely to provide a stronger signal for investments in west facing rooftop solar and batteries. These changes to our export tariffs are discussed above in our stakeholder feedback section.

Since the publication of our TSS in January 2023, there have been no structure changes to our export tariff proposal.

Bill impacts of the proposed export tariffs

We are proposing the introduction of an export pricing structure from 1 July 2024. From 1 July 2024, only customers who choose to opt-in would receive the tariff; and from 1 July 2025, all residential and small business customers on demand or TOU tariffs would be automatically assigned to the tariff. The proposed structure will:

- Include both a charge component and a reward component.
- Have a BEL of 2,500 kWh per annum over the 2024-29 period.

The FY25 bill impacts of adding on our proposed export tariff to small customer demand tariffs are presented in the table below. We note that in FY25 the export tariff is an opt-in option (before becoming mandatory in FY26).

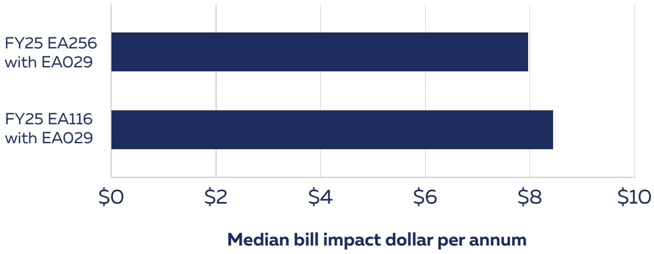
Introducing the export tariff (EA029) has led to relatively small bill impacts for small customers who have CER capability, as shown in **Table 3** and **Figure 2**.

Table 3: FY25 export tariff bill impact for customers on demand tariffs

Scenario	Sample customers with bill decrease	Sample customers unaffected	Sample customers with bill increase
Residential customer sample: FY25 EA116 (Residential demand) with EA029 (export tariff)	27%	0%	73%
Small business customer sample: FY25 EA256 (Small business demand) with EA029 (export tariff)	28%	0%	72%

19 NER, clause 6.18.5(g) – Total efficient cost and minimising distortions principle

Figure 2: FY25 export tariff median dollar impact (see previous table for tariff descriptions)



Detailed charts and analysis of export tariff bill impacts can be found in **Attachment 8.3**.

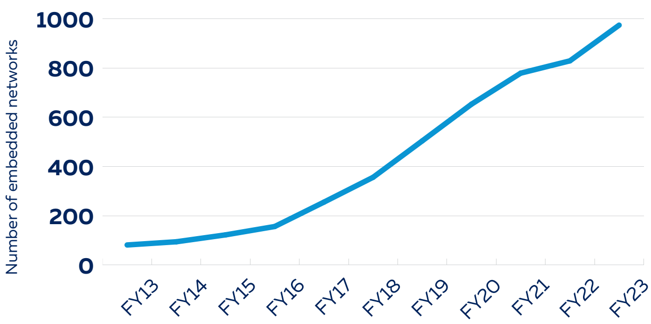
4.2 Introducing tariffs for embedded network operators

Background

Embedded networks (EN) are private electricity networks that supply multiple homes or businesses – for example, within developments such as apartment buildings, shopping centres, retirement villages, industrial estates or caravan parks. The EN operator typically connects to the distribution network via a single point, and purchases and on-sells energy to the customers located within its network.

As **Figure 3** shows, the number of ENs connected to our network has grown significantly over the past 10 years. There are now almost 1,000 in our network with an additional 5-6 connecting each month.

Figure 3: Number of ENs connected to the Ausgrid network



A typical EN in our network has an average annual consumption of around 1,000 MWh, which is equivalent to about 200 households or 50 small businesses. Most ENs are connected to our low voltage network, although some are connected at higher voltage levels.

Currently, none of our tariffs are specifically designed for EN customers. Under our tariff assignment policies, most are assigned to a low voltage medium business network tariff (either EA305 or EA310). Those that connect to our high voltage networks are assigned to our high voltage large business network tariff (EA370).

Our Proposal

Our proposal is to introduce three EN tariffs from 1 July 2024 to better reflect the costs EN customers impose on our network and ensure they make a fair contribution to residual costs. These include a tariff for:

- ENs connected to the low voltage network using between 160 and 750 MWh per annum (for ENs currently on tariff EA305);
- ENs connected to the low voltage network using more than 750 MWh per annum (for ENs currently on tariff EA310); and
- ENs connected to the high voltage network (for ENs currently on tariff EA370).

In its Draft Decision, the AER did not approve these new tariffs and sought feedback from stakeholders on additional information Ausgrid could include in its revised TSS. We have responded to the Draft Decision in a number of areas, and have included information on the proposed tariff charging components, the basis for the residual cost recovery, and the extent of avoided costs from ENs.

Tariff component structure

The proposed tariffs would have the same fixed and energy charges as the equivalent medium or large business tariff, but they would include an increased capacity charge.[20] This is an efficient way to recover residual costs among ENs as this charging component is applied to the maximum peak demand over the prior 12 months.[21] A higher capacity charge scales better and is fairer and more practical across a wide range of EN customers compared to a higher fixed charge.

We considered including a higher fixed charge in these tariffs. However, there is limited information on the number of sub-metered customers within each EN in our network area, and therefore what the size of the fixed charge should be. A fixed charge applied on a postage stamp basis would not be an efficient way to recover residual costs and it would trigger a wide range of bill outcomes.[22]

20 NER, clause 6.18.5(i) – Customer understandability principle

21 Applied to peak demand occurring in the peak period window, 2pm-8pm on working weekdays.

22 NER, clause 6.18.5(h) – Customer impact principle

We also considered increased energy charges as part of our EN tariff proposal, however these tariff components can most easily be managed if a customer installs solar PV or makes behavioural changes. Therefore it is not the preferred tariff component to recover increased residual costs.

Efficient recovery of residual costs

As the key driver of embedded network tariff reforms is recovery of residual costs, the main impact of not introducing these reforms would be the customer impacts from how residual costs are recovered. Specifically, non-embedded network customers would have to bear a greater burden of residual cost recovery. This burden would increase over time with the forecast growth in embedded networks on our network.

We have reviewed what EN customers pay in network charges and compared these outcomes to those of other customers on the same tariff. This review included analysing the network bills of these customer types connecting as an EN compared with individual customers connecting directly to our network (and instead facing residential and small or medium business tariffs, as relevant).

This analysis suggests our current tariff arrangements for EN customers are not as efficient or fair as they could be. At present, the residual cost contribution of embedded network customers is materially different based on whether they connect as an embedded network or as individual connections. This is known as "tariff arbitrage" and creates a bias in our network prices that encourages connections as embedded networks, and reduces the residual cost contribution they would otherwise make if they connected as individual connections.

Recovering residual costs in a manner which minimises distortions to efficient price signals is one of the NER pricing principles.[23] For connections such as apartment buildings, shopping centres, industrial parks or retirement villages, these connections could choose to connect to our network as one single large customer (i.e. an embedded network) or as a series of individually connected customers. Minimising distortions to efficient price signals, in this circumstance, means how we recover our residual costs should not be a key deciding factor in whether these connections choose to connect to our network as an embedded network or as individual connections.

Quantifying tariff arbitrage

The tariff arbitrage problem means more revenue is recovered from customers who aren't ENs and this can be considered an inefficient way of recovering network revenue. There are good reasons why a development might choose to connect as an EN, but in our view tariff

23 NER, clause 6.18.5(g) – Minimising distortions principle

arbitrage should not be one of them. This is because the cost savings that accrue to ENs must be recovered from other customers.

Our network bill comparison analysis (see **Tables 3 and 4**) also demonstrates the tariffs we currently assign EN customers result in lower network bills than those receiving our residential and small business rates. This means that a development's choice to connect to our network as an EN instead of connecting each individual energy user may be partly driven by a reduction in the total network bill.

Tariff arbitrage may encourage the growth of ENs in our area, which is a distortion of efficient price and results in less equitable recovery of residual costs.[24] The Rules require that recovery of residual cost should not distort price signals. Without this change our business tariffs could potentially distort price signals to customers, by creating an incentive for new embedded networks. Therefore, the tariff arbitrage opportunity represents an inefficiency and is not consistent with the NER pricing principles.

We are proposing to increase the capacity charge for ENs by 50%. This increase is calibrated to close but not fully close to the tariff arbitrage gap in our current tariffs. Our analysis indicates that if the tariff arbitrage was to be removed in full the capacity charge increase could be in the range of 78% to 135%. In our Pricing Directions Paper, we initially proposed to adopt a capacity charge percentage increase in one step in July 2029. In response to stakeholder feedback, we have proposed to transition this change over a 5 year period to July 2029.

The capacity charge increase is based on an assessment of tariff arbitrage and analysis of actual data from more than 800 ENs within our network. We have included a tariff arbitrage model (**Attachment 8.13**) with our revised proposal. The analysis shows the network revenue that would be recovered under three scenarios:

1. BAU with no introduction of EN tariffs.
2. Our proposal, with the introduction of the EN tariffs with partial removal of the tariff arbitrage with a 50% capacity charge uplift.
3. An estimate of the revenue resulting from full removal of the tariff arbitrage, and a derived capacity charge uplift.

We note that our analysis is indicative and dependent on several estimated assumptions. For example, we do not know the actual residential and business customer mix or number of child National Metering Identifiers (NMIs) in each EN in our network. This is a reason why we have not proposed separate residential and commercial EN tariffs. Despite this data limitation, our analysis indicates that the tariff arbitrage problem exists for both residential and commercial ENs. We expect that this problem could worsen as the energy mix shifts away from gas and further towards electrification.

24 NER, clause 6.18.5(g) – total efficient cost and minimising distortions principle

EN benefits and avoided costs

The AER's Draft Decision asks whether ENs create avoided costs for Ausgrid and whether this should be reflected as a benefit of the proposed tariffs. Ausgrid has not identifed material benefits as a result of an EN connecting to its network. Our assessment indicates that there are minimal avoided costs resulting from ENs. For upfront capital costs, developers fund the LV reticulation in new residential or commercial property estates. This is not a cost avoided by Ausgrid when these developments are established (including when they are established as an EN). Our regulatory proposal also assumes that assets involving capital contributions do not incur a tax liability (and this is therefore not an avoided cost).[25] For ongoing operating costs, the LV reticulation in urban subdivisions is typically located underground and requires minimal maintenance.

Customer impacts

The new tariffs would be applied to all connections within our network area that are identified as ENs in MSATS[26] and use above 160 MWh per annum[27]. This would allow small ENs such as caravan parks and small retirement villages to be exempt from the proposed changes.[28]

Other customers located in ENs operated by 'exempt sellers' have retail price protection as they cannot be charged more than the Default Market Offer (DMO). In its submission to the Ausgrid Pricing Directions Paper, Compliance Quarter said that in its experience most EN customers receive prices below the DMO. At the IPART embedded network forum held on 21 September 2023, Origin Energy (an authorised retailer) confirmed that it charges its EN customers at rates less than the DMO.

IPART is currently reviewing the retail pricing arrangements for customers located in embedded networks in NSW. Ausgrid made a joint submission (with Endeavour Energy And Essential Energy) to this consultation process and this has been included with our Revised Proposal (**Attachment 8.16**). The submission describes how our proposed EN tariffs could be accommodated within the existing DMO framework, ensuring EN operators can maintain an adequate operating margin while small customers located in ENs receive retail price reductions.

In its recent consultation, IPART received 12 submissions from consumer stakeholders and a further 23 submissions from industry. Consumers located in ENs cited high bills and a lack of flexibility in their choice of retailer. EN operators provided some support for the DMO as a form of price cap, but said any changes should consider profit margin and maintenance costs. This consumer and industry feedback was also reflected in IPART's

25 Victoria Power Networks v Commissioner of Taxation [2020] FCAFC 169 (VPN Decision).

26 Market Settlements and Transfers System.

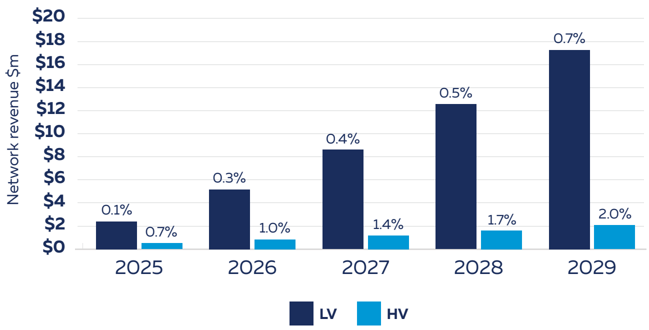
27 And are connected at low or high voltage.

28 NER, clause 6.18.5(h) – Customer impact principle

stakeholder forum held on 21 September 2023.

The new EN tariffs would not result in Ausgrid earning more revenue because we are subject to a revenue cap. This ensures that any additional revenue earned from ENs is offset by lower charges for other customers.[29] We have estimated the extent of the benefits for other customers as a result of introducing EN tariffs. The chart below shows the impact on non-EN customers if EN tariffs are not introduced. The network revenue and percentage impacts for the LV and HV tariff classes are shown separately. We note that this analysis does not include new ENs that will connect to our network in the 2024-29 period.

Figure 4: Annual benefit to non-EN customers (dollars and percentage)



The following case studies compare the network charges currently paid by ENs with those paid by equivalent customers not in ENs, and the charges they would pay under our proposed EN tariffs. The case studies included a residential EN with 315 sub-metered customers (such as an apartment building) and a business EN with 35 sub-metered customers (such as an industrial precinct). They are based on actual ENs currently connected to our network and use FY21 consumption data and our FY22 prices.

The results of this analysis are summarised in **Table 3** and **Table 4**. They demonstrate that under our current tariffs, EN network charges are significantly less than the total charges their sub-metered customers would pay if they were billed individually. They also show the extent that our fully transitioned EN tariffs would reduce this difference.

Table 3: Comparative analysis of network charges for a residential EN with 315 sub-metered customers

	Normal customer billing (315 units on EA116)	**Embedded network on EA310**	**Proposed tariff with 50% capacity charge increase**
Consumption per NMI, (kWh)	3,143	–	–
Total consumption, (kWh)	989,913	–	–
Fixed – network access charges	$45,480	$12,054	$12,054
Energy consumption charge	$22,176	$13,745	$13,745
Capacity charge	$100,268	$43,153	$64,730
Total network bill (per annum)	$167,924	$68,952	$90,529
Difference ($)		**-$98,972**	**-$77,396**
Difference (%)	–	-59%	-46%

Below is a summary of the charges for a business example – businesses on a street in an industrial precinct. The charges for the individual customer connections are compared to a single embedded network on EA310.

In this example our proposed fully-transitioned EN tariffs will close most of the tariff arbitrage opportunity. However, the EN will remain better off (by 8%) on the proposed tariff compared to what customers would pay under normal customer billing.

29 NER, clause 6.18.5(g) – Total efficient cost principle

Table 4: Comparative analysis of network charges for business EN with 35 sub-metered customers

	Normal customer billing (35 customers)	Embedded network on EA310	Proposed tariff with 50% capacity charge increase
Consumption per NMI, (kWh)	42,172	–	–
Total consumption, (kWh)	1,476,020	–	–
Fixed – network access charges	$25,984	$12,054	$12,054
Energy consumption charge	$42,898	$20,732	$20,732
Demand/Capacity charge	$84,802	$72,144	$108,216
Total network bill per annum	$153,684	$104,930	$141,002
Difference ($)	–	**$48,754**	**-$12,682**
Difference (%)	–	**-32%**	**-8%**

Stakeholder feedback on our EN tariffs

As part of the development of our embedded network tariff proposal over an 18-month period, we engaged with a range of different stakeholders and received 9 formal submissions on the topic as part of our Pricing Directions Paper consultation. We also held two PWG meetings dedicated to embedded network tariffs. We have provided a summary table of our engagement over this period (including stakeholders and timeframes) in **Attachment 8.15** to our Revised Proposal.

In its submission to our Pricing Directions Paper, PIAC supported the proposed tariffs and the minimum threshold, however it said the proposal could go further toward cost reflective levels and include a "glide path" for the introduction.

Uniting (a non-for-profit organisation managing retirement villages) commented that our proposal should differentiate between residential and business embedded networks. We considered separate EN tariffs for residential and commercial embedded networks. However, as we do not have a clear indication of the different residential and business customer types within embedded networks, we are unable to introduce separate tariffs.

NSW Caravan and Camping Industry Association (**CCIA**) recommended that our proposal should exclude land lease communities as these organisations are prevented by legislation from making a profit from the sale of energy. They suggested that these embedded networks may be able to be identified from data via NSW Fair Trading. However, Ausgrid's proposal is not specifically seeking to target embedded networks based on their level of profitability, rather on the contribution they make to total efficient cost and residual network revenue. For this reason, we don't propose to create an exemption for land lease communities.

The Shopping Centre Council of Australia said that the proposed tariffs should only be introduced for residential ENs on the basis that commercial ENs are not creating a load profile problem. They also suggested that shopping centres be treated differently as some have paid capital contributions to Ausgrid. Our proposed tariffs seek to correct some, but not all of the imbalance observed between the network costs ENs pay and other network users.

GoEvie submitted that the proposal will make it harder to install EV charging stations in shopping centres. The electricity retailer Energylocals commented that the 30% average network bill impact was not an acceptable increase. Origin Energy commented that embedded networks create efficiencies that can be shared with customers.

They also suggested that a grandfathering or transition arrangement be introduced to protect existing embedded networks. CCIA also supported a transitional arrangement for the proposed tariffs. We believe a grandfathering arrangement would not address the tariff arbitrage problem and create inequity between new and existing ENs. We have addressed the feedback on introducing a transitional arrangement in the next section.

The EV Council queried why Ausgrid was introducing tariffs specific to embedded networks, but not to EV charging stations. Our proposal is seeking to remove most of the tariff arbitrage opportunity that is currently available to the ENs located within our network. A tariff arbitrage problem does not exist for EV charging stations.

In its submission Compliance Quarter said that the Ausgrid proposal would stifle innovation. It also stated that the annual energy consumption is not correlated to the level of vulnerability of customers. It recommended that the AER commission an independent analysis of embedded network load profiles, any costs avoided by Ausgrid due to embedded networks, and the costs of "reverse retrofitting" embedded networks.

In our Pricing Directions Paper, we proposed to increase the capacity charge component and produce a 30% average network bill increase for the ENs assigned to the new tariffs. The PWG suggested that Ausgrid should go further toward removing the tariff arbitrage opportunity by increasing the capacity charge by a greater amount. We have considered this feedback and decided to not fully remove the tariff arbitrage opportunity given the range of network bill impacts experienced by each embedded network under the proposal (some have impacts of more than 30%). The PWG also considered whether specific exemptions should be created under the proposal, but concluded that this would not create an appropriate balance between efficiency and fairness.

Changes since our Pricing Directions Paper and initial Proposal

Our Pricing Directions Paper proposed to introduce the EN tariffs in full on 1 July 2024 and without a transition period. In response to stakeholder feedback we amended this proposal and propose to introduce the capacity charge uplift over five years, resulting in the tariffs reaching the proposed level by July 2029 (instead of a one-off increase in July 2024). This achieves an appropriate balance between managing bill impacts across the EN customer segment and achieving greater fairness for our other customers.[30]

We have not amended our proposed EN tariff structures since the initial Proposal in January 2023. Our assessment of the customer bill impacts have changed as a result of CPI, X factor price paths and jurisdictional schemes.

Bill impacts for affected EN customers

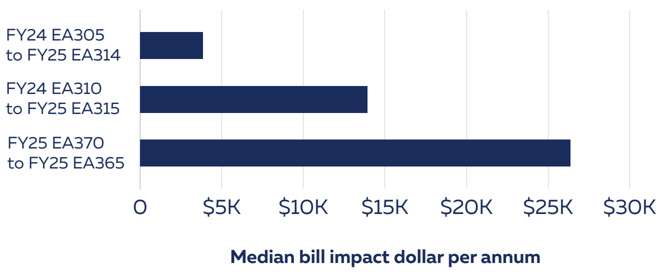
We estimate that our proposed five-year transition for EN tariffs will see a 5.7% per annum nominal increase for the affected ENs. These increases exclude other changes in the network revenue price paths in the 2024-29 period (such as inflation and interest rate impacts).

The FY25 bill impacts for EN customers currently on tariff EA305 (LV 160-750 MWh), EA310 (LV > 750 MWh) and EA370 (HV) are illustrated by **Table 5** and **Figure 5**.

Table 5: FY25 embedded network tariff bill impact

Scenario	No. of customers affected	Customers with bill decrease	Customers with bill increase
FY24 EA305 (LV 160-750 MWh pa) to FY25 EA314 (LV embedded network 160-750 MWh pa)	412	0%	100%
FY24 EA310 (LV above 750 MWh pa) to FY25 EA315 (LV embedded network, above 750 MWh pa)	312	0%	100%
FY24 EA370 (HV) to FY25 EA365 (HV embedded network)	30	0%	100%

Figure 5: FY25 embedded network tariff median bill impact (see previous table for tariff descriptions)



Detailed charts and analysis of EN tariff bill impacts can be found in **Attachment 8.3**.

30 NER, clause 6.18.5(h) – Customer impact principle

4.3 Streamlining our existing tariff offerings and tariff assignment policies

Background

In our engagement with our communities to date, we heard from retailers and aggregators that our tariff offerings and tariff assignment policies could be simplified. For example, the number of available tariffs makes it difficult to understand the differences between charging components and pass through of our price signals in retail price offers. We also heard that some of our medium and large business tariff assignment policies could be improved, so that they are fairer for customers.

In response to this feedback, we want to streamline our tariffs and modify our tariff assignment policies for the 2024-29 period.[31] We are keen to simplify our tariffs where possible, particularly as we expect some parts of our tariff schedule may become more complex in the future as we explore more dynamic tariffs (see **Section 3.3**). We are proposing to make the following changes from 1 July 2024:

- Withdrawing some residential and small business tariffs that are very similar to other tariffs or have few customers assigned to them; and
- Withdrawing some medium and large business tariffs that have few customers assigned to them or were introduced as an interim measure.

In its submission Red Energy said that Ausgrid should pick one set of cost reflective windows to apply for the 2024-2029 period and that this should be an opt-in cost reflective tariff. It also said that Ausgrid should create the streamlined new seasonal peak tariff but allow retailers and their customers to transition to the new tariff over the 5-year period. If retailers choose not to adopt the streamlined tariff over the 5-year period, Ausgrid should be able to mandatorily reassign the remaining customers to the streamlined tariff in 5 years.

In response, we believe that our proposal does prioritise one set of cost reflective tariffs. In 2024-29 we propose to continue our assignment policy of moving small customers to demand tariffs when the meter is upgraded. We will also continue to allow flexibility by allowing small customers to opt-out of demand tariffs to a TOU based tariff.

Our proposal

We propose to withdraw two tariffs for residential customers and the equivalent tariffs for small business customers. These include our transitional TOU tariffs (EA011 and EA051) and our residential and small business TOU Demand tariffs (EA115 and EA255). **Table 6** shows the number of customers currently assigned to these tariffs, and the tariffs we propose to transfer these customers to. For further details on these tariffs please refer to our TSS for the 2019-24 period.

Table 6: Residential and small business tariffs we propose to withdraw from 1 July 2024

Tariff to be withdrawn	Number of customers affected	Reason for withdrawal	The tariff affected customers would be transferred to
Transitional TOU (EA011 and EA051)	155,519 residential 2,819 small business	The tariff structure is flat, so customers are not receiving cost-reflective price signals despite having a capable meter. This means they have no flexibility to manage their bills by responding to our price signals	Customers would be moved to a standard TOU tariff: • Those on Type 4 meters would move to introductory demand tariffs (EA111 and EA251) for 12 months before moving to full demand tariffs (EA116 and EA256). • Those on Type 5 meters would move to EA025 or EA225
Residential and small business TOU Demand (EA115 and EA255)	127 residential 56 small business	These tariffs have very few customers	Customers would be moved to a standard TOU tariff (EA025 or EA225)

31 NER, clause 6.18.5(i) – Customer understandability principle

The transitional TOU tariffs (EA011 and EA051) were introduced in July 2018. Unlike standard TOU tariffs, these peak, shoulder, and off-peak rates are equal. This approach was intended to provide customers visibility of their consumption volumes within the TOU tariff structure, but without applying the actual TOU prices when calculating their network charges. We intended to transfer the customers to cost-reflective tariffs on 1 September 2019[32], but the 2019 regulatory decision prevented this from occurring.

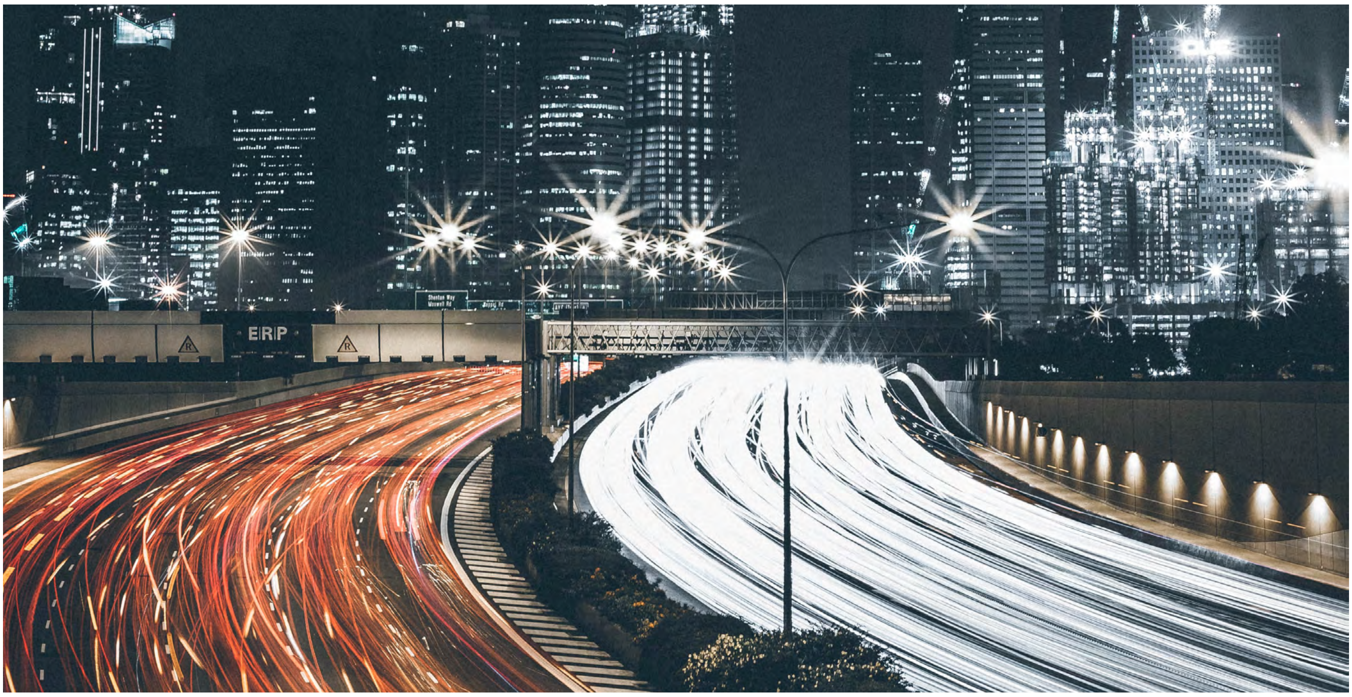
Retailers have told us these tariffs are simply duplicating existing flat tariffs without providing any material benefit to customers. They are also not always passed through by retailers. Therefore, we propose to withdraw them and move customers assigned to them to our standard cost reflective tariffs. Our demand tariffs are more cost-reflective and send price signals about the different costs of using the network at different times. This provides customers with flexibility to manage their bills by responding to our price signals.

Effected customers will receive a 12 month transition period via the existing introductory demand tariffs EA111 and EA251. This is a change from our initial proposal which sought to move these customers directly to demand tariffs (and is made as a result of feedback from a retailer). We believe this improves our tariff assignment policy as it aligns with the arrangements for other customers and provides an introduction to demand-based charging structures. The bill impacts for these changes are shown in **Table 7** below and in **Attachment 8.3**.

The residential and small business TOU demand tariffs (EA115 and EA255) were introduced in 2019 as an option for TOU tariff customers who did not want to receive the full demand component rate. We propose to withdraw them as less than 200 customers have chosen to opt into them.

In our Pricing Directions Paper, we also proposed to remove our introductory demand tariffs (EA111 and EA251). We assign small customers with meter replacements (due to failures) to these tariffs for 12 months where they receive a small demand charge. At the end of the 12-month transitional period they are assigned to their respective "full" demand tariff. This introduces these customers to demand pricing as they are able to see the cost reflective structures on their electricity bill.

We received feedback from our engagement with AER staff in October 2022 that customers on flat tariffs who have meter upgrades should have a 12-month delay before moving to demand tariffs.[33] We propose to retain the existing introductory demand tariffs (EA111 and EA251) as they already provide a 12-month transition for customers to demand tariffs. We believe this is a better approach (than customers remaining on flat tariffs for 12-months) as they will have the opportunity to understand demand charges before receiving the full price signal.[34]



32 Ausgrid, Ausgrid - amendment to the revised TSS, Attachment A and AER, Ausgrid Distribution Determination 2019 to 2024 Attachment 18 Tariff Structure Statement, p 10.

33 NER, clause 6.18.5(h) – Customer impact principle

34 NER, clause 6.18.5(i) – Customer understandability principle

In its submission, PIAC supported the removal of introductory demand tariffs and that it does not support customer opt-outs of demand tariffs. We have considered this feedback and propose to retain introductory demand tariffs in the 2024-29 period. These tariffs will enable customers to become used to the structure of the demand charge, before receiving the full rate after 12 months. We also propose to continue to allow demand tariff customers to opt-out to TOU structures, as this is consistent with our pricing principle for customer flexibility.

In its submission City of Newcastle supported the withdrawal of the tariffs shown in **Table 7**. Red Energy agreed that the proposed charging and timing windows are simpler and easier for customers to understand. However, it said that the existing tariffs should be retained, but closed to new customers instead. Ausgrid supports a withdrawal of legacy tariffs (rather than closing to new customers) as it will avoid some customers being "left behind" and unable to access cost reflective price structures.

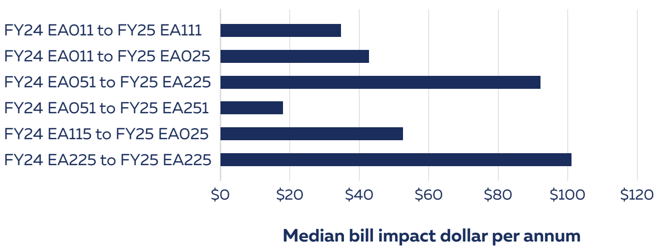
Residential and small business streamlining bill impacts

This section provides an overview of the first-year bill impact (FY25) of proposed tariff withdrawals. These changes are applicable for residential and small business customers currently assigned to transitional TOU tariffs (EA011 and EA051) and TOU Demand tariffs (EA115 and EA255). These network bill impacts include changes for inflation and regulated revenue paths. They also include the proposed changes in charging windows.

Table 7: FY25 Residential and small business bill impact – tariff streamlining

Scenario	No. of customers affected	Customers with bill decrease	Customers with bill increase
FY24 EA011 (residential transitional TOU) to FY25 EA111 (residential demand introductory)	97,952	0%	100%
FY24 EA011 (residential transitional TOU) to FY25 EA025 (residential TOU)	57,567	17%	83%
FY24 EA051 (small business transitional TOU) to FY25 EA225 (small business TOU)	1,318	18%	82%
FY24 EA051 (small business transitional TOU) to FY25 EA251 (small business demand introductory)	1,501	24%	76%
FY24 EA115 (residential TOU with demand) to FY25 EA025 (residential TOU)	127	13%	87%
FY24 EA255 (small business TOU with demand) to FY25 EA225 (small business TOU)	56	24%	76%

Figure 6: FY25 Residential and small business median bill impact – tariff streamlining (see table above for tariff descriptions)



Detailed charts and analysis of tariff streamlining bill impacts can be found in **Attachment 8.3**.

Withdraw some medium and large business tariffs

We also propose to withdraw some medium business tariffs and the equivalent large business tariffs. These tariffs are listed in **Table 8**. As this table shows, few customers are currently assigned to some of these tariffs. Therefore, we expect the withdrawal of these tariffs would have a limited overall impact. Removing these tariffs would make it easier for retailers to understand our tariffs.

The other tariffs – our transitional capacity tariffs (EA316 and EA317) - were introduced in 2018 as an interim measure to reduce bill impacts associated with the introduction of cost-reflective tariffs. We are already in the process of transitioning these customers, to meet our regulatory requirement to transfer customers on those tariffs to the cost-reflective equivalent tariff by 2024.[35] This process is on track, despite a postponement in 2020-21 due to the COVID-19 pandemic. We expect it to be complete by 1 July 2024.

Table 8: Medium and large business tariffs we propose to withdraw from 1 July 2024

<table>
<tr><th>Tariff</th><th>Customers</th><th>Why should this tariff be withdrawn</th><th>Tariff that customers will be transferred to</th></tr>
<tr><td>EA325
(LV Standby)</td><td>2</td><td rowspan="3">These tariffs have very few customers</td><td>Demand tariff EA256</td></tr>
<tr><td>EA360
(HV Standby)</td><td>7</td><td>High voltage tariff EA370</td></tr>
<tr><td>EA380
(HV Substation)</td><td>19</td><td>High voltage tariff EA370</td></tr>
<tr><td>EA391
(Substation)</td><td>0</td><td>This tariff has no customers</td><td>Not applicable</td></tr>
<tr><td>Transitional capacity
(EA316 and EA317)</td><td>2,001 and 5</td><td>The AER requires us to transfer all customers from these tariffs by 30 June 2024</td><td>Equivalent cost-reflective tariffs (EA302 and EA305)</td></tr>
</table>

Medium and large business streamlining bill Impacts

Customers currently assigned to EA325 are likely to benefit from the proposed tariff streamlining. Most customers transferred off network tariffs EA316, EA317, EA360 and EA380 are expected to face bill increases.

We propose to manage any significant impacts for customers transferring off tariffs EA360 and EA380 with a capacity reset transition for the first six months of the regulatory period. In June 2023 we consulted with retailers on these changes including the proposed withdrawal of network tariffs EA360 (HV standby) and EA380 (HV substation). The feedback was mixed as one retailer supported the proposal while others responded that the capacity reset plan was temporary and would not mitigate bill impacts in future years.

35 Ausgrid, Ausgrid - amendment to the revised TSS, 28 February 2019 and AER decision for the 2014-19 regulatory period (attachment 18, page 17).

Table 9: FY25 medium and large business bill impact – tariff streamlining proposals

Scenario	No. of customers affected	Customers with bill decrease	Customers with bill increase
FY24 EA325 (LV standby) to FY25 EA256 (small business demand)	2	100%	0%
FY24 EA360 (HV standby) to FY25 EA370 (HV)	7	0%	100%
FY24 EA380 (HV substation) to FY25 EA370 (HV)	19	0%	100%
FY24 EA316 (transitional 40-160 MWh pa) to FY25 EA302 (LV 40-160 MWh pa)	2,001	12%	88%
FY24 EA317 (transitional 160-750 MWh pa) to FY25 EA305 (LV 160-750 MWh pa)	5	0%	100%

Figure 7: FY25 medium and large business median bill impact – tariff streamlining (see table above for tariff descriptions)

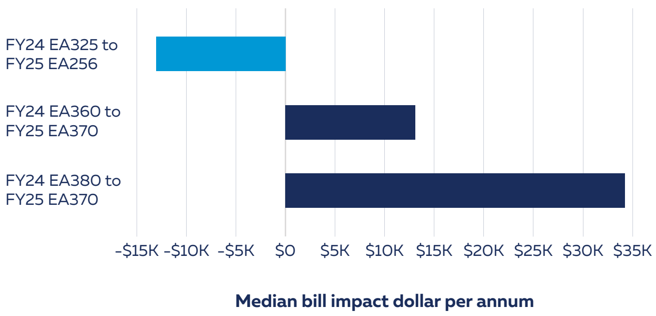
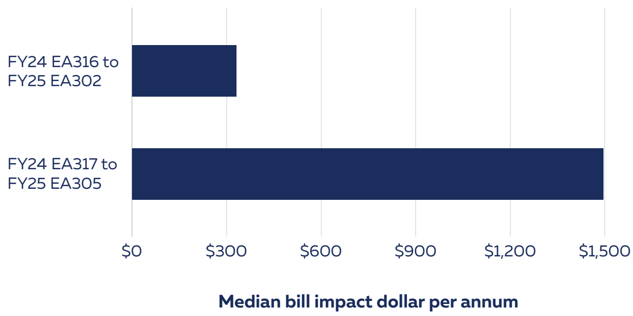


Figure 8: Withdrawal of transitional capacity tariffs, median bill impact (see table above for tariff descriptions)



Detailed charts and analysis of tariff streamlining bill impacts can be found in **Attachment 8.3**.

Reform our small and medium business tariff assignment policies

Our PWG has provided strong support for our capacity component charges for medium to large business customers. However, in our consultations to date, retailers and customers have raised two concerns about the bill impacts for small and medium business customers, when we transfer them to another tariff in line with our current tariff assignment policies.

First, when a small business customer on our demand tariff (EA256) uses more than 40 MWh pa over a 2-year period, our policy is to transfer them to a medium business capacity tariff (EA302). This tariff has a different structure to the demand tariff, and this can create adverse bill impacts for customers who use the network infrequently (such as, currently, electric vehicle charging stations).

Second, when new business customers connect to our network, they do not have any existing metering data to guide us in assigning them to the most appropriate network tariff. Our current policy assigns them to a demand tariff if they have a single-phase connection, and to a capacity tariff if they have a three-phase connection. However, we understand that many small business customers (using less than 40 MWh pa) are on three-phase supplies. Under this policy, they are assigned to a capacity tariff that is likely to be inappropriate. In addition, under our existing assignment policies a new customer must wait 12 months before they can request a tariff transfer. For these reasons, we propose the following reforms to our tariff assignment policy:

- **Increasing the consumption threshold** for transferring existing customers from a demand tariff to a capacity tariff from 40 MWh pa to 100 MWh pa. This will align with the threshold at which the NSW ombudsman scheme and National Energy Retail Law (NSW) defines a small customer. It will also improve our annual review of tariff assignments by reducing the number of tariff transfers occurring. It will also enable customers using between 40 and 100 MWh per annum to be assigned to the business demand tariff EA256 (and to opt-out to a TOU tariff, should they choose to).[36] We propose to move the threshold to 100 MWh in 20 MWh steps over three years (FY25, FY26 and FY27) to limit rebalancing of tariff components and possible customer bill impacts.[37]

Stakeholder feedback on tariff streamlining

Our Pricing Directions Paper consultation asked stakeholders for their views on our changes to new and existing medium business customer tariff assignment. Northern Beaches and Willoughby Councils supported lifting the usage threshold from 40 to 100 MWh pa, as it would result in lower bills for business customers, including for councils.

In its submission, the EV Council said that the proposed reforms were moving slightly in the right direction. It requested that the assignment threshold between demand and capacity tariffs be moved to 160 MWh per annum (instead of 100 MWh). Evie Networks agreed with this position.

We believe that 100 MWh per annum is an appropriate threshold to distinguish between small and large business customers as it aligns with the National Energy Retail Law Regulation (NSW) definition of a small customer. It also is the threshold below which the NSW energy ombudsman scheme applies. Our proposal is to apply demand tariffs to small customers and capacity-based tariffs to large customers as this reflects an appropriate balance between efficient, cost reflective pricing and fairness.

The move to the 100 MWh thresholds will improve our tariff assignment policy by ensuring new business customers are more likely to be assigned to the correct tariff at the time of connection. On this basis it is an appropriate assumption for new business tariff assignment.[38]

If business customers who are assigned to capacity tariffs are allowed to opt-out to demand or TOU tariffs it will reduce the benefits of this cost reflective structure. Under our proposed system of assessment and review we will ensure than any businesses using less than 100 MWh (and on capacity tariffs) will be transferred to demand tariffs once they have 12 months of meter data.

Amendments since the initial Proposal

The consultation to the AER's Issues Paper included submissions from EV public charging station proponents, including the EV Council and Evie Networks. These submissions proposed we align our assignment threshold for large customer tariffs with Endeavour and Essential Energy. This would mean that customers using below 160 MWh per annum would receive demand charges instead of capacity charges and be able to move to TOU tariffs, should they choose to do so.

The EV Council subsequently proposed an alternative amendment to our tariff assignment policy for medium business customers. Instead of moving the threshold to 160 MWh, it would move customers using less than 160 MWh per annum and more than 100 kW to demand tariffs. We currently have about 400 customers who meet this criteria, and they include schools, sports grounds, and public EV charging stations.

The July 2023 Ausgrid PWG meeting considered the feedback from submissions to the AER's issues paper. We presented the EV Council's proposal as an option for amendment, in the context of revenue trade-offs and customer bill impacts. The bill impact analysis showed the extent that customers would be worse off as a result of the proposed business customer assignment policy. If the EV Council amendment were implemented, it would increase other customers' network bills by 0.3% as a one off impact in FY25. At the meeting there was general agreement that the amendment to our proposal was acceptable, both in terms of acceptable bill impacts and to avoid limiting the growth of public EV charging stations.

Given the PWG and EV Council feedback we have amended our assignment for medium business customers for the next regulatory period. From 1 July 2024, we propose to assign existing and new customers using less than 160 MWh per annum and more than 100 kW to our EA256 demand tariff. Identification of eligible customers will be included in our annual assessment and review of tariffs as part of the annual price proposal process.

We have also removed reference to the 100 amp rule in our tariff assignments for medium business customers. This change will avoid an inconsistency between whether a 100 amp or 100 kW threshold applies to new and existing business customers.

For clarity, we are retaining the following policies from our initial TSS proposal:

- to move the assignment threshold between demand and capacity tariffs from 40 MWh to 100 MWh over three years.
- to allow customers who are on network tariff EA256 (demand) to opt out and move to the EA225 (time of use) tariff.

100 MWh threshold bill impacts

By July 2027 we propose to increase the threshold for assigning existing business customers to capacity tariffs to 100 MWh pa. In FY25 this means that existing capacity charge customers using between 40 and 60 MWh pa will be moved to demand tariffs. Eligible smaller business customers currently assigned to the capacity tariff (EA302) will be reassigned to the business demand tariff EA256 and benefit from bill reduction as shown in **Figure 9**.

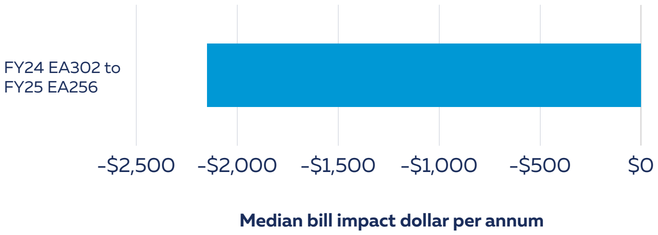
36 NER, clause 6.18.5(i) – Customer understandability principle

37 NER, clause 6.18.5(h) – Customer impact principle

Table 10: EA302 customers 40- 60 MWh bill impact

Scenario	No. of customers affected	Customers with bill decrease	Customers with bill increase
FY24 EA302 (LV 40-160 MWh pa) to FY25 EA256 (small business demand)	8,804	100%	0%

Figure 9: EA302 customers 40-60 MWh median bill impact (see table above for tariff descriptions)



Detailed charts and analysis of the bill impacts of these changes can be found in **Attachment 8.3**.

4.4 Simplifying and updating the charging windows

Residential and small business customers on our demand and TOU tariffs are charged more in summer and winter, when there is peak demand on our network. This is efficient because peak demand is a major driver of our network costs. Charging higher prices in peak demand periods signals these higher costs to customers, who can then make informed decisions about whether to consume energy when it is most convenient for them, or when it costs them less.[39] However, over the past four years, only around half of retailers have passed through our demand charges. This may be because our current charging windows are more complex than those of other distribution networks.

Our proposal

To improve the cost reflectivity of our price signals[40] and to increase the likelihood of customers receiving our price structures[41], we are proposing the following:

- Making the peak charging window consistent in summer and winter, and moving it to later in the day, so that from 1 July 2024 peak pricing applies from 3pm to 9pm in both seasons;
- Having the option to further move the peak charging window from 1 July 2027, so that peak pricing applies from 4pm to 10pm in both seasons;
- Extending the number of days per week that the peak charging window applies from five to seven for residential customers;
- Combining the off-peak and shoulder charging windows so that off-peak charges apply at all times in spring and autumn and outside of the peak charging window in summer and winter; and
- Removing the low season peak demand charge so that demand charges do not apply outside of the summer and winter periods.

The sections below discuss each of these changes in more detail. **Table 11** provides an overview of proposed charging windows for small customers and compares them to the existing charging windows.

39 NER, clause 6.18.5(f) – Long run marginal cost principle

40 NER, clause 6.18.5(f) – Long run marginal cost principle

41 NER, clause 6.18.5(i) – Customer understandability principle

Table 11: Comparison of current and proposed seasonal peak charging windows for our small customers

Time of use tariff	Current residential	Proposed residential	Current small business	Proposed small business
November to March (summer) and June to August (winter)	**Peak:** 2pm-8pm weekdays (summer) **Peak:** 5pm-9pm weekdays (winter) **Shoulder:** 7am-10pm all days except when peak applies **Off-peak:** 10pm-7am all days	**From 1 July 2024:** **Peak**: 3pm-9pm all days **Off-peak:** all other times **Option:** **From 1 July 2027:** Peak: 4pm-10pm all days **Off-peak:** all other times	**Peak:** 2pm-8pm weekdays **Shoulder:** 7am-10pm weekdays except when peak applies **Off-peak:** 24 hours on weekends and 10pm-7am weekdays	**From 1 July 2024:** **Peak**: 3pm-9pm working weekdays **Off-peak:** all other times **Option:** **From 1 July 2027:** Peak: 4pm-10pm working weekdays **Off-peak:** all other times
April, May, September, and October	**Shoulder:** 7am-10pm all days **Off-peak:** 10pm-7am all days	**Off-peak:** all times	**Shoulder:** 7am-10pm weekdays days **Off-peak:** 24 hours on weekends and 10pm-7am weekdays	**Off-peak:** all times

Demand tariff	Current residential	Proposed residential	Current small business	Proposed small business
November to March (summer) and June to August (winter)	**High season peak:** 2pm to 8pm weekdays (summer) **High season peak:** 5pm to 9pm weekdays (winter)	**From 1 July 2024:** 3pm-9pm all days **Option:** **From 1 July 2027:** 4pm-10pm all days	**High season peak:** 2pm to 8pm weekdays	**From 1 July 2024:** 3pm-9pm working weekdays **Option:** **From 1 July 2027:** 4pm-10pm working weekdays
April, May, September, and October	**Low season peak:** 2pm to 8pm weekdays	No demand charge	**Low season peak:** 2pm to 8pm weekdays	No demand charge

Note: For large business customers the peak window will also move to 3pm to 9pm. Capacity charges will continue to apply on working weekdays and energy charges in high season months. The shoulder and off-peak periods will also be combined for these customers.

Combining the peak charging window and the shoulder charging window

Shoulder period prices have historically played a role in keeping peak demand within the peak charging window. By providing a two-hour separation between evening peak and off-peak charges, they allowed demand to fall from peak levels before price-responsive demand was added to the network. However, retailers have told us that administering the existing shoulder charging windows for small customers involves an additional degree of complexity.

Our energy rates have been progressively reduced in the 2019-24 period, as per the AER's 2019 decision.[42] Most of our shoulder rates will soon be at similar levels to the corresponding off-peak rate, indicating limited gain in retaining a separate shoulder rate. This can be seen in the rates on our current network price list. Despite this trend there has been a decrease in peak events occurring outside the peak charging window. This means there would likely be little difference in an efficient price for a shoulder and an off-peak charge.

We also seek to encourage "solar soaking" load in the middle of the day to help accommodate more export capable devices in our network. Having lower energy rates in the middle of the day will help with this objective.[43]

Given the considerations described above, we propose to combine our existing off-peak and shoulder periods into a new off-peak period with a wider window. Our proposed change will have a minimal impact on customer bills, given the two charging rates are already approaching alignment.[44] We have provided the bill impacts for the first year in which these changes occur (FY25) in **Attachment 8.3**.

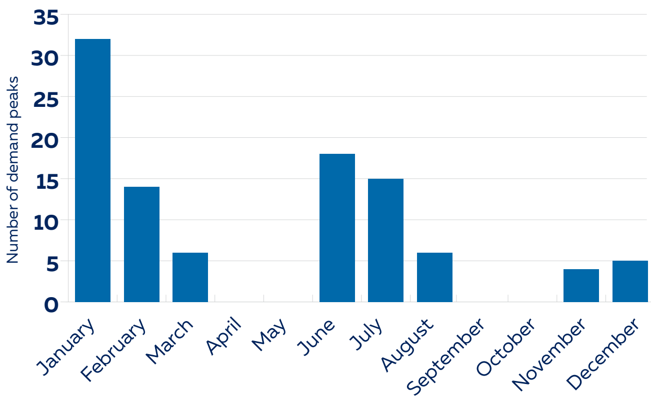
In its submission to our Pricing Directions Paper, the retailer Red Energy said that changes to network tariff structures can add to its operational and administrative costs. In response to this feedback, and a desire to minimise impacts on our retailers, we will continue to show the shoulder period component (with zero values) in the network billing files we send to our retailers.

Making seasonal peak charging window consistent in summer and winter and moving it to later in the day

Currently, our demand and TOU tariffs include higher charges at specified times of the weekday November to March (summer) and from June to August (winter). This is because, when we introduced these tariffs, the system wide demand on our network occurred almost entirely in these seasons.

We have reviewed the system-wide demand on the network over the past four years. As **Figure 10** shows, this seasonal pattern of demand has not changed. Therefore, we think it remains efficient and fair to charge customers more for using the network in those peak seasons than we do in the other months of the year. We also propose to withdraw low season demand charges which will remove demand-based charging from the April, May, September and October months.[45]

Figure 10: Count of top 100 system peak demands (2017-2021) by month



However, we propose to adjust the length and timing of the peak charging window so it is consistent in both seasons, and occurs later in the day. Currently, this window includes the six hours from 2pm to 8pm in summer, and the four hours from 5pm and 9pm in winter. We are proposing to change it to the six hours from 3pm to 9pm in both summer and winter from 1 July 2024.

42 Ausgrid, Revised Proposal – Attachment 10.01 Tariff Structure Statement, January 2019, p 6-7, and AER's final decision for the 2019-24 regulatory period (attachment 18, page 17).

43 NER, clause 6.18.5(f) – Long run marginal cost principle

44 NER, clause 6.18.5(h) – Customer impact principle

45 NER, clause 6.18.5(f) – Long run marginal cost principle

Our review of the timing of peak demand suggests that the benefits of maintaining the differences in these charging windows (in terms of improved cost reflectivity) are outweighed by the costs (in terms of increased complexity).[46] To address this, we think we should increase the length of the winter charging window to six hours. We consider this is more efficient than shortening the summer charging window to four hours because:

- The peak charging component is set to recover the LRMC of consumption services and residual revenue. Allocating this cost over a 4-hour period instead of a 6-hour period would result in a higher unit price (all other things being equal). This could exacerbate the bill impacts of customers who are unable to load shift during a 4-hour window.[47]
- If the peak price level were to become too high relative to other times of the day, it may lead to new demand peaks immediately after this charging window, as more customers delay using the network until the window closes. We want to avoid creating new demand peaks on our network, particularly as EV time-based charging becomes more common.[48]

We consider the proposed peak charging window of 3-9pm better matches the timing of peak demand than the current windows. Our analysis indicates that this change will significantly increase the number of peak demand events that fall within the peak window:

- Over the past 5 years, 92% of system-wide peaks have occurred in the proposed window of 3pm to 9pm, while only 83% have occurred in the current peak window; and
- Over the past 3 years, 82% of annual zone substation peaks have occurred in the proposed window, compared to 52% in the current peak window.

We are also aware that our review of an appropriate peak window must be forward looking and address expected demand profile changes in the 2024-29 period.[49] Our analysis indicates that the period of the day when there is peak demand will continue to shift to later over the 2024-29 period. **Figure 11** and **Figure 12** shows our forecast of the time of day that each zone substation will be at or near its peak demand in summer and winter in 2029, and largely within our proposed peak charging window of 3pm to 9pm.

Figure 11: Forecast 2029 distribution of zone substation summer peak demands [50]

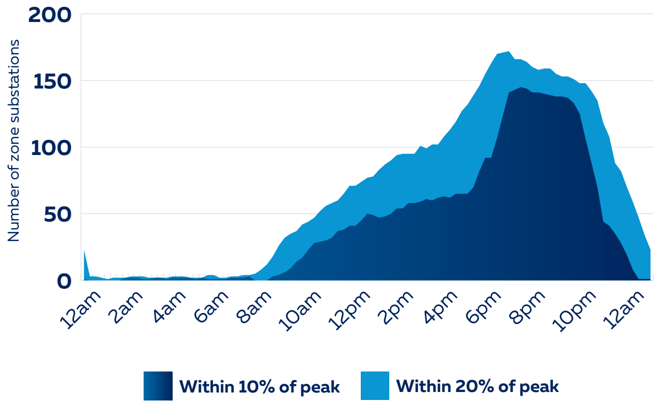
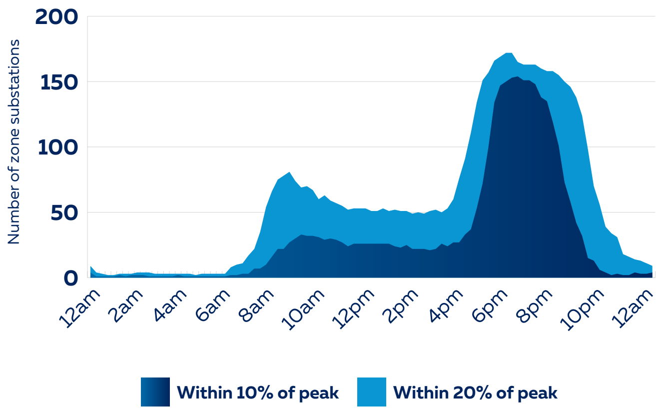


Figure 12: Forecast 2029 distribution of zone substation winter peak demands



Having the option to move the peak charging window again from 1 July 2027

As noted above, our proposed peak charging window from 1 July 2024 is based on our current forecast of the timing of peak demand over the 2024-29 period. However, the future is uncertain, and the ability to amend the TSS within-period is currently constrained under the Rules.

For example, the EV uptake rate and EV charging patterns over the period to 2029 are highly uncertain. If the take-up rate exceeds current expectations, the associated additional load could drive new evening demand peaks. We are less concerned of this occurring after 10pm given that other household load drops off significantly from this time.

Second, the increasing uptake of rooftop solar is reducing the demand on our network in the afternoon, when the volume of customer-generated energy typically peaks.

46 NER, clause 6.18.5(f) – Long run marginal cost principle; NER, clause 6.18.5(i) – Customer understandability principle

47 NER, clause 6.18.5(h) – Customer impact principle

48 NER, clause 6.18.5(f) – Long run marginal cost principle

49 NER, clause 6.18.5(f) – Long run marginal cost principle

50 These two charts show a count of substations where forecast demand as a percentage of the zone substation's forecast peak is greater than 80%.

In locations where solar penetration is already high, high levels of customer exports and low levels of demand for imports is resulting in a lower 'minimum system load' in the afternoon than previously experienced overnight. If this continues, it could increasingly drive additional voltage management costs in the low voltage network in the future.

We seek AER approval for an option to move the peak charging window to 4pm to 10pm from 1 July 2027, which would help us address these issues if they eventuate: [51]

- Extending the window to 10pm would create an incentive for customers to move their EV charging activity to after this time, ensuring it does not coincide with other (non-EV-related) load. Existing loads typically decline rapidly around 10pm and we expect this pattern to continue, particularly in the residential segment; and
- Moving the start of the window back to 4pm could increase grid imports between 3pm and 4pm, and thus it could help moderate the impact on future minimum system load costs.

The trigger event for this option will be the occurrence of a network system demand peak occurring after 9pm on any day prior to 1 March 2027. The trigger will be determined using the half-hour interval that the maximum raw coincident system demand occurred. This data will be prepared on a similar basis to the approach used for table 5.3.1 of the annual Regulatory Information Notice submission.

Extending the peak charging window to weekends for residential customers

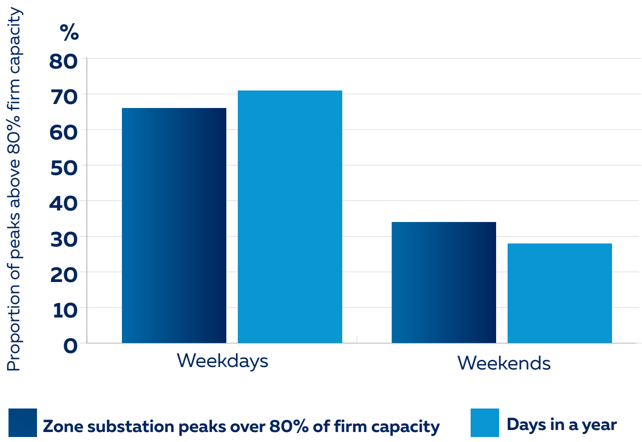
Currently, our peak charging windows apply only from Monday to Friday. This is because historically, the periods of peak demand across the whole network have occurred predominantly on working days. Of the top 160 coincident network peaks[52] in the last 5 years, only 14% occurred on weekends.

However, when we analysed the periods of peak demand in individual zone substation areas (we have around 190 zone substations with the necessary data), we found that these localised peaks are as common on weekends as on weekdays (see **Figure 13**).

51 NER, clause 6.18.5(f) – Long run marginal cost principle

52 The coincident network peak is the aggregate maximum demand that occurs across the Ausgrid network at the same point in time.

Figure 13: Zone substation peaks by day of the week



Looking closer at this data, we found that localised peaks on the weekend are most common in highly residential areas or holiday areas. Weekend peaks are significantly less likely in predominantly commercial areas, and the probability of weekend peaks declines as the proportion of residential customers in these areas declines.

Given these findings, we are proposing to extend our peak charging window so that it applies on weekends as well as weekdays for residential customers only. This would improve the cost reflectivity of our peak pricing for these customers. [53]

This change would increase the total number of hours that the peak charging window applies per year for residential customers. Because the peak price level is set to recover the LRMC of meeting peak demand, increasing the hours over which it can be recovered would decrease in the price level (all other things being equal).

Stakeholder feedback on charging window changes

Our Pricing Directions Paper consultation asked stakeholders for their views on our proposed changes to the charging windows. In our interviews with large business customers (including Opal, Qenos, Woolworths and Telstra), we heard general acceptance of the move of the peak period to later in the day. This was because the load profiles of these businesses are generally flat and are not likely to create an impact to their network costs. City of Newcastle also supported moving the peak window to 4-10pm. However, Transport for NSW commented that this proposed option will reduce the length of the off-peak window and introduce uncertainty for their planned investments in electric buses. They prefer certainty for the full five-year regulatory period as it would remove a significant amount of risk. We note that while the peak window ends later in the day, the off-peak window will

53 NER, clause 6.18.5(f) – Long run marginal cost principle

extend until 3pm the next day, (or 4pm if the trigger occurs) effectively increasing the time available for EV charging.

In its submission PIAC said that it did not support a consistent 6-hour window for summer and winter. It said that it is materially harder for households to respond to peak tariffs longer than 3 or 4 hours, and that most peaks in most parts of Ausgrid's network can be captured in a 4-hour period. As described above we have considered this trade off and are of the view that a lower peak price in a 6-hour window achieves a better balance (considering the efficiency, flexibility and fairness principles) than a higher price in a 4-hour window.

PIAC does not support moving the peak window to later if it is predicated on the increasing penetration of EVs. Our proposal to move the peak window to 3pm-9pm is not influenced by the expected take up of EVs. Our historical analysis of demand peaks (described above) shows that significantly more of the demand peaks seen in the last three years will be captured by the change to 3pm-9pm.

PIAC suggested that the expected future uptake of EVs could be managed by EV specific tariffs (and instead of having a trigger event for moving the peak period to 4pm-10pm). Ausgrid currently allows small customer EV charging to occur on its controlled load tariffs, and we will continue this arrangement in the 2024-29 period. EV specific tariffs face a barrier as distribution networks do not have visibility of EV ownership. We also consider that our proposed tariff structures provide suitable cost reflective incentives for EV charging.

PIAC said it has not seen sufficient evidence for extending the residential peak windows to weekends. It said this proposal would limit the capacity of households across Ausgrid's entire network to manage their exposure to peak pricing in the interest of capturing the peak period of a relatively small portion of the network. Our analysis (described above) does show that zone substations with predominantly residential loads are triggering peaks on weekends.

Red Energy said that making the new seasonal peak charging windows more cost reflective will ensure that the price signals for the use of the network are more accurate. However, it considers that there is little benefit in changing the timing windows twice within the 5-year period as customers need consistency to make meaningful changes to their consumption profile. Given the reasons outlined above, we are of the view that the peak charging window trigger is a prudent initiative given the uncertainty on EV take up in the next regulatory period.

Red Energy also said that Ausgrid should create the streamlined new seasonal peak tariffs but allow retailers and their customers to transition to the new tariffs over the 5-year period. If retailers choose not to adopt the streamlined tariff over the 5-year period, Ausgrid should be able to mandatorily reassign the remaining customers to the streamlined tariff in 5 years. We consider that the Red Energy proposal would result in an unnecessary delay in moving customers to cost reflective price signals, and it is worthwhile to commence the changes at the start of the next regulatory period.

Bill impacts of FY25 charging windows and price updates

This section provides an overview of the bill impacts on customers who will remain on their existing demand, TOU or capacity tariffs in FY25. These impacts are partly due to the the changes in charging structures, and also due to the assumed revenue path and CPI assumptions for FY25.

Table 12 and **Figure 14** illustrate the network bill impacts of residential and small business demand tariffs.

Table 12: FY25 demand and TOU tariff bill impact - combined factors

Scenario	No. of customers affected	Customers with bill decrease	Customers with bill increase
FY24 EA025 (residential TOU) to FY25 EA025	345,053	6%	94%
FY24 EA116 (residential demand) to FY25 EA116	258,812	7%	93%
FY24 EA225 (small business TOU) to FY25 EA225	70,904	26%	74%
FY24 EA256 (small business demand) to FY25 EA256	14,950	11%	89%

Figure 14: Demand and TOU tariff median bill impact - combined factors (see table above for tariff descriptions)

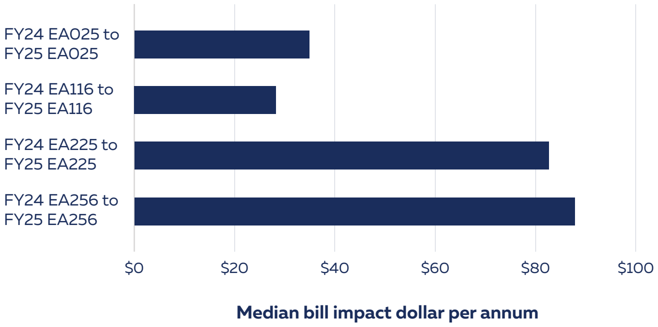
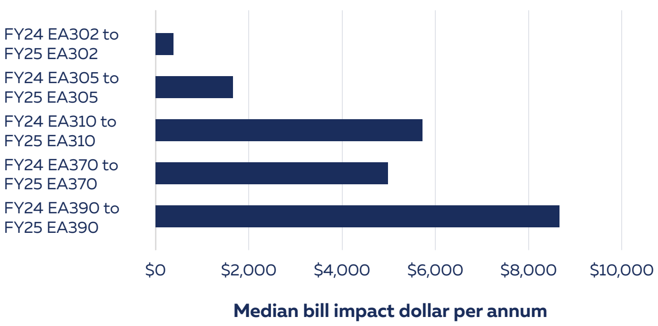


Table 13: FY25 capacity tariff bill impact – combined factors

Scenario	No. of customers affected	Customers with bill decrease	Customers with bill increase
FY24 EA302 (LV 40-160 MWh pa) to FY25 EA302 (LV 60-160 MWh pa)	13,810	11%	89%
FY24 EA305 (LV 160-750 MWh pa) to FY25 EA305	7,550	9%	91%
FY24 EA310 (LV above 750 MWh pa) to FY25 EA310	2,851	2%	98%
FY24 EA370 (HV) to FY25 EA370	296	3%	97%
FY24 EA390 (ST) to FY25 EA390	76	3%	97%

Figure 15: FY25 demand tariff median bill impact - combined factors (see table above for tariff descriptions)



Detailed charts and analysis of export tariff bill impacts can be found in **Attachment 8.3**.

4.5 Utility scale storage tariffs

Background

We expect to see significant investment in storage by our customers in coming years. AEMO forecasts embedded storage (battery) installations in NSW to grow from 180 MW in 2021-22 to 2,382 MW in 2028-29 under the Step Change scenario.[54]

While we are starting to see the take up of behind-the-meter storage, we have not yet seen utility scale storage facilities connect to our network. We currently have no existing large storage customers apart from the Ausgrid community batteries. Most utility scale storage customers currently connect to the transmission network, partly driven by lower prices relative to existing network tariffs. We seek to promote efficient levels of utility scale storage connecting to our distribution network in the 2024-29 period and beyond.[55] The connection of utility scale storage to our network – with appropriate network price signals – promotes an efficient, flexible and fair outcome to all our customers by:

- Encouraging storage to charge during periods of low demand and high voltage, thereby providing voltage support to the network, reducing the amount of rooftop solar exports being curtailed by our customers and reducing the costs of voltage management; and
- Encouraging storage to export during periods of peak demand, which can avoid us needing to augment our networks.[56]

There has been a growing debate on introducing new and innovative network tariffs to support the integration of storage into the grid:

- Each of the Victorian DNSPs proposed to the AER, in their 2021-26 TSS process, to exempt utility scale batteries from their network tariffs if operated to the net benefit of their customers.
- The AEMC reviewed the transmission and distribution network charging arrangements in its *Integrating Energy Storage Systems* into the National Electricity Market rule change review.[57]

In its review the AEMC only made a minor amendment to the distribution pricing rules, instead noting it considered further work was required on how network costs are recovered from storage.[58] In the Victorian TSS process, the AER did not accept the distributors' proposals to exempt storage from network tariffs. It instead preferred to maintain the status quo for the second round of TSS's, for consistency with the network tariff arrangements of other DNSPs outside Victoria.[59]

54 AEMO, 2022 ISP – Inputs, assumptions and scenarios workbook, June 2022.

55 NER, clause 6.18.5(g) – Minimizing distortions principle

56 NER, clause 6.18.5(f) – Long run marginal price signals

57 AEMC, Final rule determination – Integrating energy storage systems into the NEM, December 2021.

58 AEMC, Final rule determination – Integrating energy storage systems into the NEM, December 2021, p.65.

59 AER, Final decision – Victorian DNSPs – Distribution determination 2021 to 2026 – Attachment 19 TSS, April 2021, p.18.

The AER also stated:

> We anticipate specific pricing for grid-scale batteries may be a feature of the pricing reforms in the third round of tariff structure statement assessments, given the nature of the policy and regulatory reforms currently underway. As more grid-scale batteries are integrated into distribution networks, electricity distributors are likely to identify innovative ways to reflect the locational and dynamic costs of serving customers. This may result in alternative pricing structures, particularly if they are associated with differentiation in the use of network services by customers currently in the same tariff class.[60]

Given the significant storage forecasts expected over the 2024-29 period, we consider it is important that we develop efficient, flexible and fair network charging arrangements for storage. We also understand each NSW distributor is proposing specific arrangements for storage in its TSS proposal.

Our proposal

We propose to introduce three new storage tariffs on 1 July 2024. The three tariffs differ by voltage level of connection. Each tariff has a separate tariff code and tariff structure for when storage is importing (versus exporting). The three tariffs are:

- Local network support service tariff for low voltage storage (EA334/EA335);
- High voltage network storage tariff for high voltage storage (EA374/EA 375); and
- Sub-transmission storage tariff (EA394/EA395).

The eligibility and specific design of these tariffs is explained below.

Our storage tariffs will be available to customers that use the network to store electricity for export at a later time, from the same connection point. Electricity imported at the connection point can only be used to power the storage facility or be stored for subsequent discharge of electricity. Electricity exported at the connection point may only be sourced from stored energy via electricity previously imported at the connection or pre-existing at time of connection. For example, storage connected with solar PV or with an additional load behind the same connection point would not be eligible.

We may publish further requirements in our ES7 Network Price Guide to ensure we are consistent with the implementation of the AEMC's integrating energy storage systems rule change.

60 AER, Final decision – Victorian DNSPs – Distribution determination 2021 to 2026 – Attachment 19 TSS, April 2021, p.19.

Utility scale storage only connections have unique characteristics which we consider warrant specific tariff arrangements. These are: [61]

- Highly flexible and price responsive forms of demand – this means highly cost reflective tariffs can be applied with minimal customer impacts because the load can respond to these efficient price signals.
- Connections where the investment decision is primarily driven by energy cost considerations – this supports the application of locational price signals to these tariffs. Locational price signals are efficient and supported by the NER, but not applied to other customers because of customer impact considerations and the cost of calculating and conveying locational price signals.
- Largely new forms of investment – this also means there are fewer customer impacts because we are establishing the pricing signals before many customers have made the decision of where to connect and what their business operation looks like. It avoids uneconomic pricing signals which could result in new storage connections choosing to instead connect to the transmission network or without regard to local network constraints because of the manner we collect residual network costs.

Stakeholder feedback to the Pricing Directions Paper

Our Pricing Directions Paper explained our current community battery tariff trials and asked stakeholders for their views on what innovative tariff trials we should introduce for energy storage in the 2024-29 period:

- City of Newcastle supported the tariff trials and the continued use of a critical peak pricing tariff for community batteries as a trial tariff;
- Shell Energy responded that Ausgrid should introduce a utility scale storage tariff in the 2024-29 period to ensure large batteries aren't disincentivised from connecting at the distribution level. Ausgrid's current distribution tariff for sub-transmission connections was considered uneconomic for batteries, and a tariff with rates similar to the Ausgrid transmission tariff would be more appropriate; and
- Firm Power stated that trial tariffs are "unbankable" to the investment community given that distributors update their sub-threshold applications annually. The submission said a large-scale storage tariff should recognise the benefits that batteries provide and not have capacity or fixed charge components, and be exempt from receiving the NSW Climate Change Fund levy.

Responding to stakeholder feedback

In light of the feedback we received from storage proponents on the "unbankable" nature of trial tariffs, we propose to introduce storage tariffs as standard tariffs in the 2024-29 period. Starting with the design of our community battery tariff trials, we have reviewed and refined our proposed storage tariff structures. The proposed storage tariffs and their charging components are outlined in the TSS compliance paper.

We have developed LRMC based price structures for storage. The three tariffs all use a critical peak pricing approach to best match network costs to network prices. We consider that critical peak pricing best signals to customers the time that network usage (both imports and exports) drives network costs.

For our critical peak charges, we have applied energy charges over demand based rebates to signal network costs. The strength of energy charges for critical peak prices is that the signal to support the network, or avoid harming the network, is equal across the high load or minimum demand event. Demand charges could drive storage assets to only support the network for 30-minutes (the minimum interval required to maximise reward payments), with little incentive to provide further network support.

Each of our critical peak and minimum energy events are intended to be locational. [62] That is the peak or minimum energy event will ideally reflect the locational conditions of the storage asset. However the AER's Draft Decision on the ERP upgrade provides for only $18 million (instead of the proposed $149 million). This decision may impact our capability to apply these tariffs on a locational basis in the 2024-29 period. Locational pricing requires development of either expanded or new platform functionality and is not currently supported by the SAP billing and MBS metering systems.

In each tariff we will set the distribution use of system charges equal to the long-run marginal cost at the time that activity drives future costs. The LRMC applied to each tariff depends on the network voltage and the event type.

61 NER, clause 6.18.5(f) – Long run marginal cost principle; NER, clause 6.18.5(h) – Customer impact principle; NER, clause 6.18.5(g) – Minimizing distortions principle.

62 NER, clause 6.18.5(f)(3) – long run marginal cost principle – locational consideration

Table 14: How long-run marginal cost is reflected in the tariff charging components

Event	How LRMC is reflected in the tariff charging components
Local network support service tariff (LV) – critical peak energy events	The low voltage consumption LRMC is applied as a charge for imports and a reward for exports during peak energy events.
Local network support service tariff (LV) – critical minimum energy events	The low voltage LRMC, developed for our export tariff, is applied as a reward for imports and a charge for exports during minimum demand events.
High voltage network storage tariff – critical peak energy events	The high voltage consumption LRMC is applied as a charge for imports and a reward for exports during peak energy events.
Sub-transmission storage - critical peak energy events	A bespoke LRMC charge for energy use above the network reliability measure reflects bringing forward the replacement of a sub-transmission substation by 5 years, and the potential costs of overloading network assets. A reward applies when the customer avoids exceeding the network reliability measure, and reflects the value of otherwise unserved energy from an outage that would have likely occurred if the storage facility did not provide network support.
Sub-transmission storage tariff – peak energy	The sub-transmission consumption LRMC is applied as a charge for imports during peak energy events, when local network assets are operating up to 5 MW below the network reliability measure.

Ausgrid recovers NSW jurisdictional schemes (such as the Climate Change Fund) through volumetric energy charges for all customers. For our proposed storage tariffs, the off-peak import charges will include recovery of the jurisdictional schemes.

We are required under the NER transitional rules to include a basic export limit (that provides a free level of export) for any tariff involving export pricing. The policy rationale for the basic export limit is that a distribution network's intrinsic level of CER export hosting capacity should be provided without charge. However, that rationale does not apply in this circumstance. A peak export charge should only apply when voltages on our network are forecast to exceed Australian standards, a situation that indicates network hosting capacity is exhausted. In this situation there should be no unused intrinsic hosting capacity available to the storage customer. We have included a 1 kWh per event BEL for the low voltage storage tariff export charges. This is the lowest BEL we can practically apply.

Storage customers are unique in terms of their total efficient costs. By applying and responding to efficient network price signals, storage assets have relatively low avoidable and standalone costs:

- The avoidable cost of a flexible storage customer located in our network will typically be near zero. In some cases, where flexible storage customers support the network the avoidable costs are negative as their network use delays or avoids future augmentation expenditure.
- The standalone costs of a flexible storage customer are also typically very low. Flexible storage customers are primarily focused on wholesale and ancillary service markets, therefore their standalone cost is the cost of the storage connecting anywhere with access to the NEM. At larger scales the standalone costs are best represented by the prices offered to flexible storage customers by Transgrid, which we understand is significantly lower than our prevailing tariffs.

We consider that it is important that the total efficient costs allocated to flexible storage customers are between the avoidable and standalone costs. This ensures that storage customers are not creating or receiving an economic cross subsidy.

Our tariffs ensure storage customers contribute to Ausgrid's residual cost recovery, reducing the network costs allocated to all other customers. We are attempting to ensure that residual cost recovery does not deter customers from connecting to the network. In this sense we are aiming to maximise residual revenue recovery by encouraging storage facilities to operate in our network.

To comply with the NER and improve pricing efficiency, we will allocate residual DUOS to the annual fixed charge (NAC). We expect that flexible storage customers will have a high price elasticity of demand. This means that allocating cost recovery to variable usage charges may have significant distortions on efficient network usage.

Similarly, the demand charge for the sub-transmission storage tariff will recover transmission use of costs (**TUOS**). This ensures that the broader customer base will not see increases in the TUOS components of their bills due to the sub-transmission storage customer.

Given the type and nature of large-scale storage customers we consider that our suite of storage tariffs is very capable of being understood by its future customers.

We have consulted with storage proponents. These customers are highly engaged in energy markets, working primarily in wholesale and ancillary service markets. We consider that the customer impacts for our suite of storage tariffs are acceptable:

- Apart from the Ausgrid funded community battery trial customers, we have no existing storage customers. Therefore, potential customers can choose not to connect to the Ausgrid network and avoid our storage tariffs.
- Storage customers can avoid the highest charges, and accrue payments, by responding to the critical peak price events. The low voltage and high voltage tariffs create the potential for a responsive battery to avoid network charges when there are sufficient high load and high voltage network events.

4.6 Updating our controlled load tariffs

Our controlled load tariffs make supply available to residential and small business customers at a very low cost per kWh for a specified number of hours a day, in particular to heat electric hot water systems.

In return, we can control when we make this supply available, to help us manage system demand peaks. Historically, these peaks have occurred during the day and early evening, so our controlled load tariffs have specified that supply will be available within certain windows (mostly overnight).

Currently, almost half a million customers are assigned to these tariffs (mostly residential customers). We estimate that the associated controlled load reduces our system demand peaks by 300 MW in winter and 100 MW in summer.[63]

However, the number of customers on controlled load tariffs has been slowly decreasing by about 1% per year, as electric hot water systems are replaced with gas and solar thermal alternatives. This trend may continue if more customers with rooftop solar seek to move their hot water load to their primary meter, so they can benefit from offsetting their consumption with locally generated energy.

Our proposal

To stem this decline, we have updated our controlled load tariffs to make them more attractive to customers, while continuing to maximise the benefits for the network. The proposed switching times shown in Table 15 are available as an option for our retailers until 30 June 2024, after which they will be the default arrangement for customers with smart meters.

Table 15: Proposed changes to controlled tariffs in current period

Tariff	Default arrangements 2019-24	Proposed arrangements
EA030 controlled load 1 (suitable for large hot water systems)	Supply is usually available for up to 6 hours duration from 10pm to 7am	Supply is usually available for at least 6 hours in any 24-hour period, from midnight to midnight
EA040 controlled load 2 (suitable for smaller hot water systems)	Supply is usually available for 16 hours a day including more than 6 hours between 8pm and 7am and more than 4 hours between 7am and 5pm	Supply is usually available for at least 16 hours duration within any 24-hour period, from midnight to midnight, with more than 4 hours between 7am and 5pm

63 Ausgrid Demand Side Participation submission to AEMO.

We think that these changes will improve the relevance of our controlled load tariffs as the uptake of rooftop solar continues to increase over the 2024-29 period. As daytime wholesale energy prices continue to decline, moving more of the controlled load window to these times is expected to reduce retail prices for customers. This will mean we can continue using controlled load to manage system demand peaks while also helping to 'soak up' some of the abundant solar export energy available in the afternoon and reduce the impact on the low voltage network.

We will continue to work with retailers and metering providers to allow greater scope for optimisation by retailers for customers with smart meters, within the nominated tariff times. Ausgrid is currently undertaking a flexible load tariff trial (for EVs) with at least 22 hours of supply availability per day. In future years we also intend to trial a tariff that allows EV charging from power poles. Further tariff trials being considered include helping solar customers self-consume on controlled load tariffs (which is not currently possible) and testing critical peak pricing as an alternative. We also intend to trial other tariffs, where control of the load is shared on a dynamic basis for the mutual benefit of customer and network.

Responding to stakeholder feedback

Our Pricing Directions Paper consultation asked stakeholders for their views on our proposed changes to controlled load switching times. Red Energy preferred that the current control load tariffs remain in place as the proposed changes will create additional costs for retailers to comply with the changes but only result in a marginal difference. We are of the view that the proposed changes will provide clear benefits to reducing emissions and to the low voltage network (as described earlier in this section). This was demonstrated by Ausgrid's successful solar soak trial for controlled load (in which AGL and EnergyAustralia participated).

PIAC responded that controlled load tariffs and associated enabling technology should support different usage applications including EVs, heat pumps, pool pumps and batteries. We note that Ausgrid currently allows EVs, pool pumps, and householder appliances to be connected to controlled load circuits (and controlled load tariffs). The device must be permanently connected to the controlled load circuit to be eligible.

Our proposal for amending controlled load switching times has not changed since the Pricing Directions Paper.

Impact of pricing on network investments

Cost-reflective network tariffs can encourage customers to use energy in ways that place less pressure on the network. This can reduce the need to augment the network and limit network charge increases for everyone in the long term. To what extent depends on how retailers package up the network tariff with the cost of energy and what other information or tools they make available to improve a customer's awareness, understanding and ability to adapt to tariffs.

Our demand forecasts look at historic trends, economic outlook and population growth to anticipate the likely load on the network. This in turn informs the investments we make to ensure we can meet customers' anticipated demand. With customers increasingly investing in smarter, more flexible assets such as electric vehicles, home batteries and home automation, we anticipate that if we get it right and work collaboratively with customers and retail partners, cost-reflective network tariffs can have a larger impact on the usage patterns we see on the network and minimise the network investments we need to make. This is particularly important as government looks to incentivise the electrification of transport and other sectors, bring on additional load and distributed generation as we work to a Net Zero future.

We included in our January 2023 proposal a report by Houston Kemp (**Attachment 8.6**) that describes how our tariffs can help manage customer usage profiles and future augmentation of the network. The focus of this analysis was to compare two scenarios of future EV charging; one with network price signals and one with uncoordinated charging (with no price signals). The results showed that network expenditure can be reduced via network tariff structures and price signals. Further, there are clear benefits in continuing to improve our cost reflective network tariffs and component structures for the 2024-29 period.

For the 2024-29 period we have included a response to anticipated EV load profiles in our tariffs, targeting what we consider is the factor that will have the most impact over this period. We will also continue to do trials and collaborate with customers and retailers over this period and strengthen our evidence base for the link between cost-reflective network tariffs and usage profiles.

Our TSS also includes analysis of the linkages between expenditure for increasing PV penetration and prices. Our export LRMC analysis is based on 16 case studies of low voltage distributors located throughout our network. The case studies were sampled to produce a range of different distributor types, such as regional and metropolitan locations, and areas with high or low CER penetration. This modelling shows a positive LRMC, meaning that over the long run, a kilowatt of investment in solar capacity triggers an associated cost. We have reflected these LRMC values in our proposed export tariff, to give a cost reflective price signal to CER customers. Further information on our export LRMC is provided in our TSS compliance paper.

CER and underlying demand forecasts

6.1 Overview

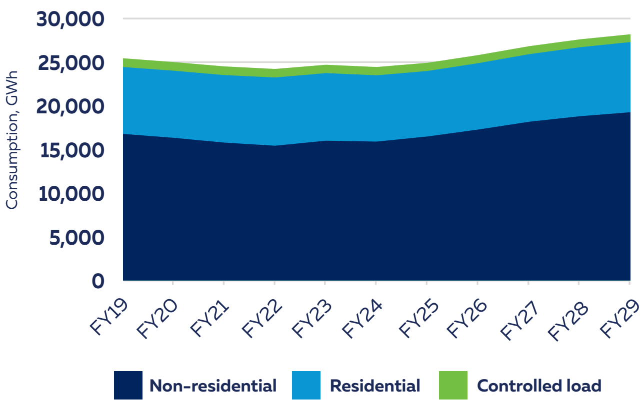
This section explains how we have prepared the volume forecasts for the tariff charging components as part of Ausgrid's TSS for 2024-29. The energy volume forecast is prepared by combining an underlying econometric model projection with post-model adjustments for CER, energy efficiency, and major customer loads.

The high-level consumption forecast is largely unchanged since Ausgrid's initial Regulatory Proposal for 2024-2029 as dated January 2023. The changes to this forecast are:

- Update of smart meter uptake in line with AEMC's final decision on metering arrangements (August 2023);
- Changes in tariff allocation rules in line with the updated TSS; and
- Updates to estimates of customer volumes for the export tariff.

The following figure shows the overall energy consumption forecast to 2029. The decline in consumption due to COVID-19 starts to recover post-FY22 due to growth in customers, the general economy, EVs and major connections such as data centres. These factors are, to a degree, offset by projected energy conservation outcomes due to increasing solar penetration, the impacts of the NSW Energy Savings Scheme and improvements in building and electrical appliance efficiency.

Figure 16: Overall consumption forecast

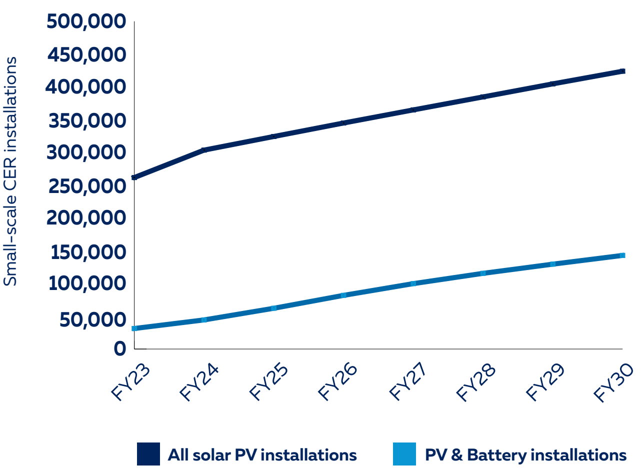


6.2 Growth in customer uptake of CER

Rooftop solar and battery uptake

The number of residential and small business customers generating electricity through their rooftop solar systems has been growing over the past 15 years. We use an in-house CER model to forecast the behind- the-meter consumption from rooftop solar and batteries. We are expecting to see strong growth over the 2024-29 period, both in the number of customers with solar in our network and the average system size. We are also starting to see growth in small residential and business customers installing batteries (see **Figure 17**). We expect that the installed capacity of batteries on our network will grow to 1.7 GWh by around 2030.

Figure 17: Ausgrid network area small-scale CER installed capacity (Ausgrid projection)



By 2029, we expect rooftop solar uptake will nearly double in our network area; and the number of batteries will increase around eight-fold. The resulting behind-the-meter (self) consumption is expected to increase from 670 GWh in FY22 to 1,590 GWh in FY29.

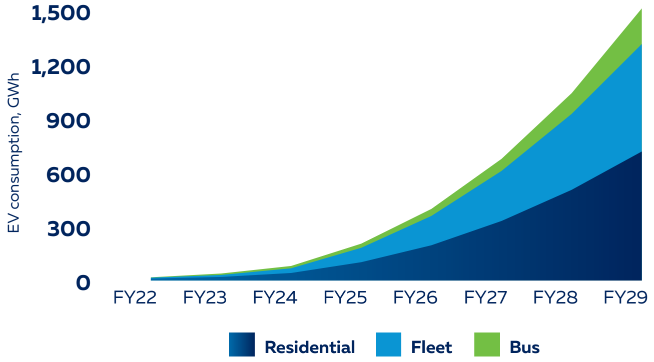
Forecast growth in EV uptake

We expect to see significant growth in the number of customers owning EVs in our network area over the 2024-29 period and beyond. Charging EVs can use a lot of electricity over a very short period. For example, we are already seeing on the market:

- Commercial chargers with up to 350 kW capacity; and
- Home smart chargers with a typical capacity of 7 kW chargers.

We worked with the consulting firm Evenergi to develop an EV model which forecasts EV uptake. A strong uptake in energy for EV charging is expected in the next regulatory period, increasing the consumption from 20 GWh in FY22 to 1,500 GWh in FY29 (see **Figure 18**).

Figure 18: Forecast electric vehicle energy consumption in Ausgrid's network



Source: Ausgrid/Evenergi modelling

Our forecasts for EV, rooftop solar and battery uptake are aligned to 2022 AEMO Integrated System Plan (ISP) and use the Step Change scenario as the base case.

6.3 Energy consumption forecast

Establishing the baseline for the current year

This first year of the energy volume forecast (or "baseline") establishes the starting point of the projection. Several underlying factors have influenced our forecast of the FY23 year. The lingering impacts of COVID-19 lockdowns 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 below trend due to the impact of the two lockdown periods on businesses in 2020 and 2021.

In preparing the first year volume forecasts (for FY23), the following factors have been taken into account:

- **Abnormal year-to-date weather:** Australia experienced a third year of the "la nina" weather pattern in FY23. This results in cooler and wetter weather which supresses energy consumption. In summer 2021/22, the impact of 'la nina" was calculated to be 230 GWh, reducing the consumption from what would be an average summer. The forecast assumed a similar impact in summer 2022/23.
- **Underlying energy growth:** At the time of preparation of this forecast, total energy consumed (weather corrected) has grown in the July to September 2022 period by 4.7 compared to the same period last year. This reflected the recovery from the COVID-19 lockdowns in the same period in 2021. We assumed that the recovery would continue until December 2022 after which it will align with the same level of (weather corrected) consumption in the same period previous year.

The table below shows that our forecast for FY23 energy consumption has a 0.9% decline in residential consumption and 3.7% growth in non-residential consumption, as compared to FY22. The overall volumes were expected to increase by 2.0% in FY23.

Table 16: Volume forecast for FY23 compared to FY22

Consumption, GWh	FY22	FY23	Change
Residential	7,811	7,737	-0.9%
Controlled Load	981	960	-2.1%
Non-residential	15,433	16,008	3.7%
Total	24,225	24,706	2.0%

Underlying energy consumption

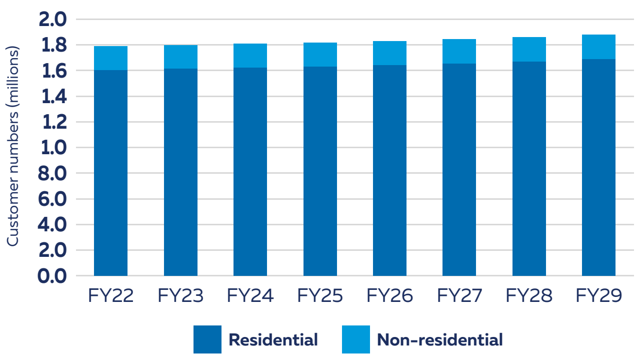
We use an established econometric model which defines the relationship of energy consumption with several economic indicators. The residential and business segments use underlying energy consumption or 'electricity services' data from 2003 as the dependent variable. Electricity services is weather corrected consumption data that has the impacts of CER and energy efficiency initiatives removed. The historical electricity services for residential and non-residential customers are modelled against the separate independent variables. These independent variables are underlying drivers of the forecasts and include new connection numbers, gross state product (**GSP**), a 3-year rolling electricity price index, and residential household disposable income (**RHDI**).

The results of the historical trend analysis establish the elasticity values which can be used in the projection model.

To produce the 2024-29 forecast of underlying energy we use the GSP and RHDI forecasts from the step change scenario in AEMO's Electricity Statement of Opportunities (**ESOO**) 2022. The GSP and RHDI forecasts are expected to increase steadily in the forecast period, whereas the electricity prices see a considerable increase in FY22 and FY23, followed by a period of volatility to 2029.

The residential model is calculated on a per customer basis. We therefore need a residential customer forecast to calculate the total residential consumption over the forecast term. To forecast these customer numbers, the Housing Industry Association's (**HIA**) dwelling starts forecast is used until FY25, followed by the household projections of NSW Department of Planning and Environment. Our current forecast of customer numbers for 2024-29 are shown in **Figure 19** below.

Figure 19: Customer Number Forecast to 2029 Post model adjustments



Post model adjustments

Post model adjustments are modelled separately before being applied to underlying energy consumption forecasts. They allow adjustments for items whose trends cannot be fully captured by the econometric model. These post model adjustments include:

- Forecast rooftop solar, batteries and electric vehicles;
- Estimated energy efficiency improvements for household appliances and buildings; and
- Major customer loads (such as new data centres and rail projects).

The energy efficiency forecast is aligned with AEMO's ESOO 2021 forecast inputs, with 2 exceptions. These are the NSW Energy Savings Scheme (ESS) and Peak Demand Reduction Scheme (PDRS) with forecasts in line with the latest developments in these areas. The overall energy efficiency impact is expected to increase by 2,760 GWh between FY22 and FY29.

Figure 20: Residential post model adjustments (incremental to FY23)

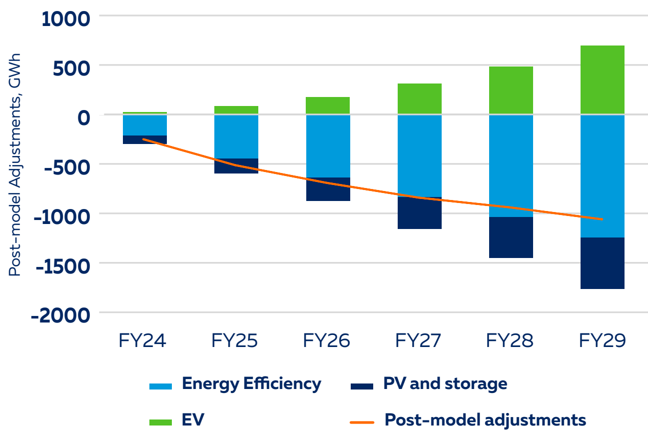
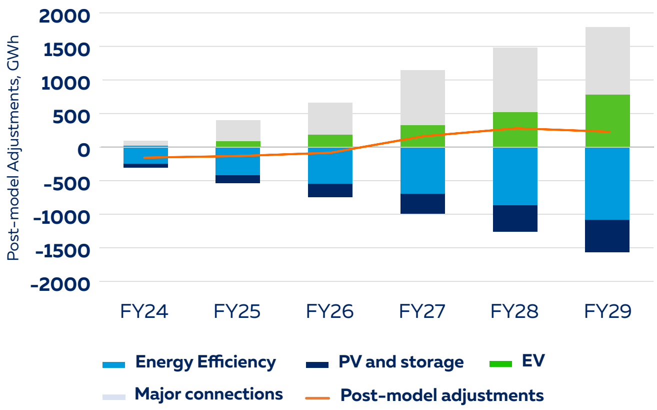


Figure 21: Non-residential post model adjustments (incremental to FY23)



Final energy consumption forecast

The final energy consumption forecast is produced by combining the modelled forecast and the post-model adjustments. The residential energy consumption is expected to increase by 1.2% per annum, and the non-residential energy consumption is expected to increase by 3.9 % per annum between FY24 and FY29. Controlled load is expected to decline in line with the recent trends by 1.3% per annum.

Figure 22: Residential projection

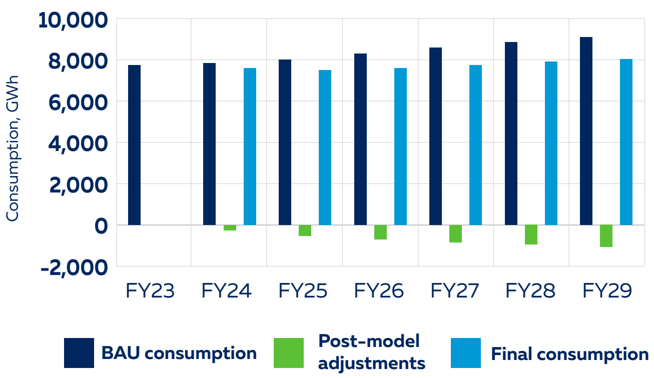
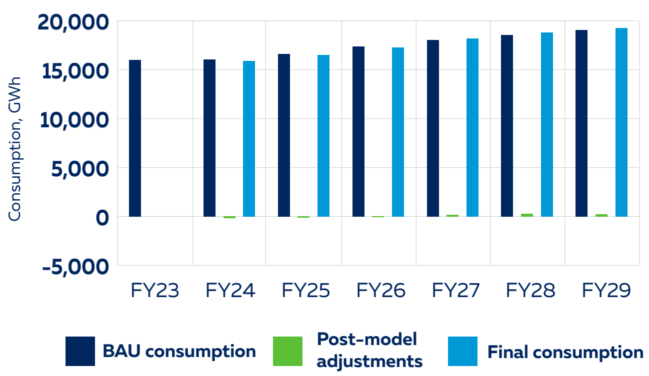


Figure 23: Non-residential projection



Our total energy usage to FY29 is expected to decrease by 0.8% between FY19 and FY24, followed by an increase of 2.9% per annum between FY24 and FY29.

Similar trends are expected in NSW, and are reflected in the most recent forecasts from the market operator. According to the step change scenario of AEMO's ESOO 2023 forecast, total energy usage to FY29 in NSW is expected to decrease by 1.5% between FY19 and FY24, followed by an increase of 2.3% per annum between FY24 and FY29.

The final volume forecast for residential and non-residential segments are distributed across tariffs based on historical trends and changes in tariff assignment policies. The detailed forecast by tariff and tariff component can be found in **Attachment 8.9**.

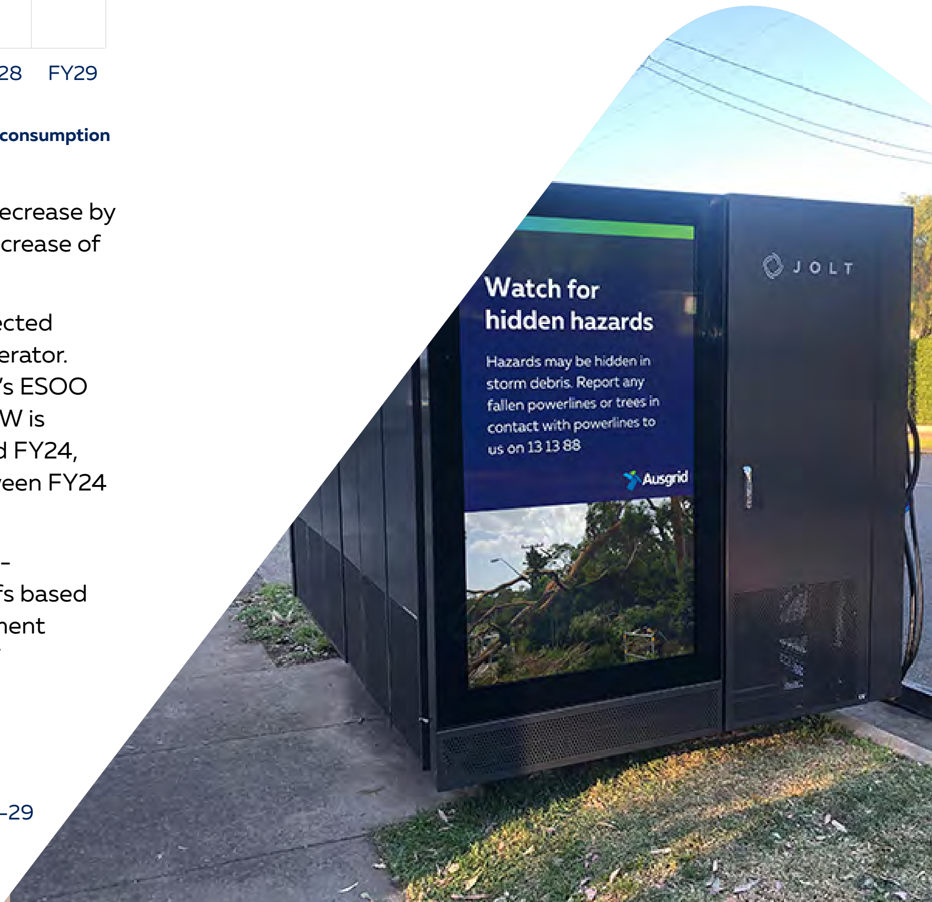
6.4 Tariff and tariff component allocation

Our proposed tariff assignment policy will see small customers with meter upgrades assigned to demand tariffs (after the one-year assignment to introductory demand tariffs, if applicable). New small customers will be immediately assigned to demand tariffs. The customer bill impacts of moving to cost reflective tariffs are presented in **Attachment 8.3**.

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 almost 1 million customers with basic meters.

We note that in August 2023 the AEMC published its final report on its review of the regulatory framework for metering arrangements. The report recommends a target of 100% uptake of smart meters by 2030 in the NEM jurisdictions. It also says that legacy accumulation and manually read interval meters are to be progressively retired by the DNSPs under a legacy meter retirement plan, and retailers are required to replace the retired meters within a set time frame.

Our smart meter forecast assumes that 100% of our customers will have a smart meter installed by 2030. This aligns with the metering forecast provided in the AER's September 2023 draft decision on Ausgrid's regulatory proposal.



Contact us

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