Tariff Structure Explanatory Statement

2024-29 Regulatory Control Period

30/11/23

Endeavour Energy

POWER together

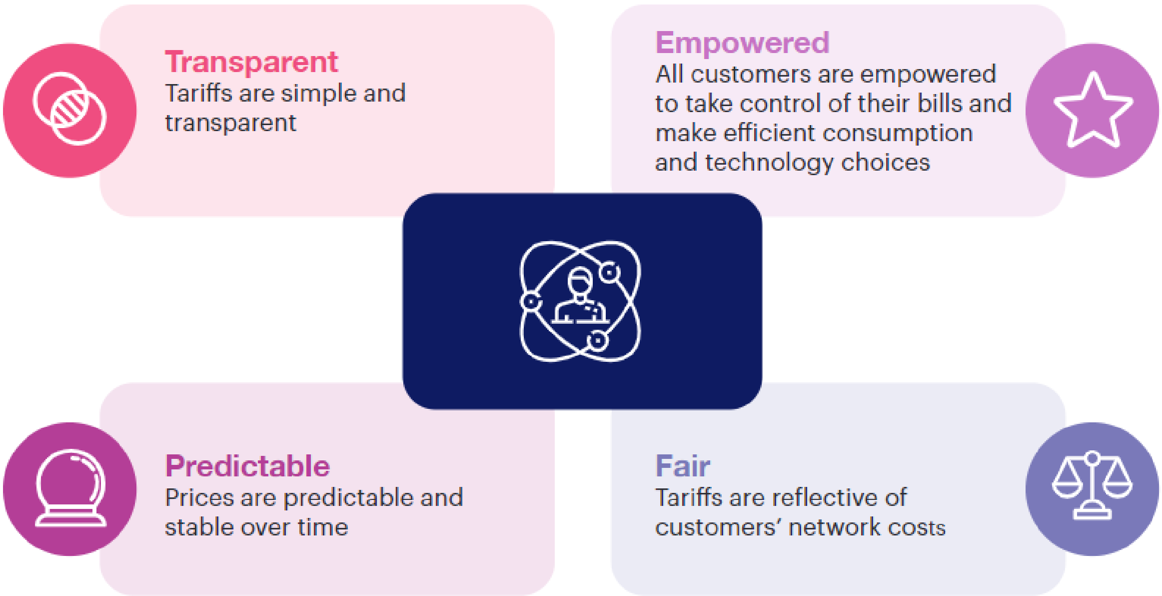
Contents

Executive summary

Our tariff strategy

Network tariffs are how customers are charged for their network service and energy usage. Endeavour Energy charges network tariffs to retailers, who then pass them onto customers. These tariffs enable Endeavour Energy to recover the revenue needed to build, operate and maintain our network to transport electricity to our customers.

The underlying principles to our approach to tariffs are outlined below.



In developing our tariff strategy and tariff structure statement, we have engaged with a range of stakeholders and customers. This has included both end-customers key customer advocates. This has also included holding several workshops with retailers, large Battery Energy Storage System (BESS) providers and other market participants such as small generation aggregators (SGA), who can pool and sell energy generated and exported back to the distribution network by our customers from rooftop solar, batteries or electric vehicles.

Efficient network pricing requires a clear and causal link between customer network use and the costs that this use imposes. We engaged with our stakeholders on our long-term capital and operating costs and how these could be most efficiently reflected in and impacted by tariffs. As a result, we propose to incorporate both import and export price signals into our tariffs. This requires an estimation of the forward-looking efficient costs, or long- run-marginal-cost (LRMC), for both imports and exports. Our estimates of LRMC include those components of forward-looking network expenditure that could be avoided through a change in the timing of a customer's consumption or generation.

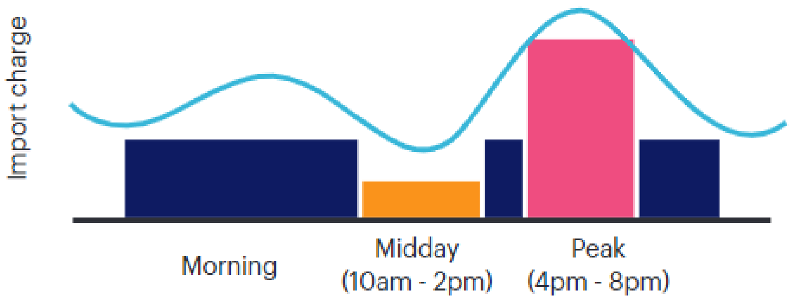
For our proposed export tariffs, we are also required to offer a basic export level to customers without charge, which allows a retail customer to export to our network up to this level at no additional charge. This basic export level is closely linked to the pre-existing, inherent export hosting capacity of our network and reflects the baseline level of export power flows that can be supported without the need for additional network expenditure.

Cost-reflective tariffs

For the 2024-2029 period, Endeavour Energy is proposing to accelerate the transition of customers to cost-reflective tariffs, which better reflect the costs of distributing electricity on our network at different times of the day and year. Cost-reflective tariffs (which include off peak and peak rates) are considered fairer because customers are charged based on how and when they use the network. Cost-reflective tariffs allow customers to make better decisions about how to manage their electricity consumption, enabling them to save on their bills.

As cost-reflective tariffs better reflect the costs of distributing electricity on the network, they can also encourage more efficient use of the network by customers. When thousands of customers make small changes to how they use the network, this can help to reduce peak demand in the evenings. Over time, this will help to reduce how much additional investment is required to deliver a reliable service, helping to keep network costs down for all customers.

Cost-reflective tariffs will result in lower prices in the middle of the day during 10am-12pm when demand for electricity and use of the network is low and exports of rooftop solar to the network are highest. Conversely, there will be higher prices in the evening on weekdays from 4pm-8pm when the demand for electricity is high and the network is at its busiest as people come home from work and school.



Tariff structures and times remain constant between high and low seasons. All prices are based on energy (c/kWh). Peak prices change between seasons.

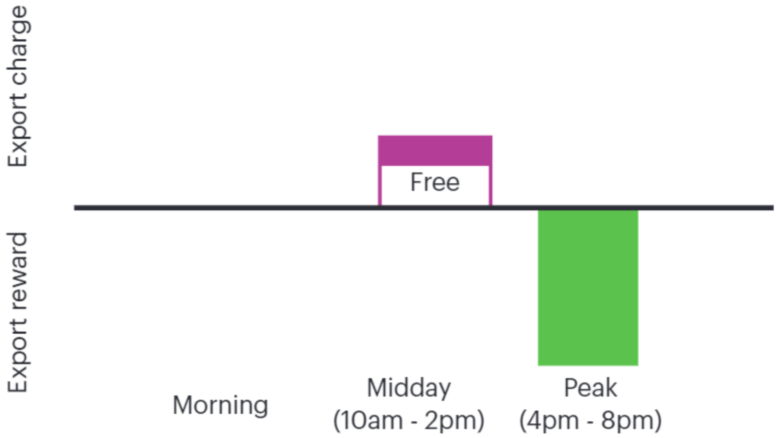
Export tariffs

Two-way export tariffs or “prosumer tariffs” relate to how customers are rewarded or charged for exporting excess energy that they generate back to the network, for example from rooftop solar. Export tariffs are cost-reflective tariffs that can help to improve how the network is used, encourage more customers to purchase new technologies, and avoid the need for additional inefficient investment in the network.

For the 2024-2029 period, Endeavour Energy is proposing to enable existing customers to opt-in to an export tariff from 1 July 2024. From 1 July 2025, new and upgrading customers who export energy back to the grid would be moved onto the export tariff but would be able to opt-out if they choose.

We are proposing to charge for energy exports to the network in excess of a 1,750 kWh per annum threshold from 10am-2pm in the middle of the day to encourage customers to use the electricity they are generating rather than export it to the network. This will help to limit pressure on the network’s stability due to excess solar generation and reduce the need for upgrades to the system, the costs of which would have to be passed onto all customers.

Conversely, we are proposing to reward customers for exporting electricity during times of high electricity demand from 4pm-8pm on weekdays to encourage customers to export the excess energy they are generating for other customers to use when it is most needed. The reward proposed for customers exporting energy at periods of high demand in the evening is significantly greater than the charge proposed for customers exporting excess energy above the minimum threshold during the middle of the day.



Efficient large energy storage and embedded network tariffs

We are in a unique position to rethink our large-scale commercial tariffs to better accommodate connections of new and emerging technology. We are looking to efficiently incentivise large and community scale grid-connected batteries to connect to our network with cost and reward mechanisms, as well as fast EV charging.

We have also reassessed our approach to charging embedded networks (privately owned and managed electricity networks that often supply all premises within a specific area or building), which will ensure all customers pay for their fair use of the network.

Our Proposal looks to incentivise these connections while ensuring they make a fair contribution to network costs.

Impact of our proposed tariff strategy

Over the 2024-29, we forecast our tariff strategy will lead to:

- 71% of our customers on cost-reflective tariffs by 2029, up from 8% in 2022. The forecast growth in customers on cost-reflective tariffs will be affected by the roll-out of smart meters to customers.
- More efficient integration of electric vehicle charging, batteries and increasing rooftop solar exports to the grid through new tariff structures, which will encourage customers to move their electricity usage to times of lower network demand and generation to times of higher network demand, saving all customers money over the long-term.
- An almost 1% reduction in maximum demand by 2029 from existing connections across our network, which will reduce costs for all customers over the long-term.

These forecast benefits will depend on the extent to which retailers pass through our cost-reflective tariffs to customers. We will continue to work closely with retailers to understand what support customers may need to facilitate the transition to cost-reflective tariffs and ensure customers can benefit from the long-term savings these tariffs can provide.

How cost-reflective tariffs impact different customers

To help customers better understand how cost-reflective tariffs will work, during our engagement program we developed a range of examples to show how cost-reflective tariffs could impact different customers.

For each customer below, we have outlined the:

- Current flat tariffs in 2025 (not cost-reflective)
- Impact of cost-reflective tariffs compared to the current flat tariffs
- Impact of shifting use from peak periods (evenings) and into off-peak periods (in the middle of the day or overnight), assuming a 10% shift in consumed energy from peak to off-peak periods
- The total impact of cost-reflective tariffs and moving energy use away from peak periods compared to current flat tariffs.

In the example, some customers with solar are paying more, since their consumption in the evening peak remains high and this reflects the costs they place on the network.

The impacts below demonstrate the annual distribution network costs for different customers (which account for less than one third of their total electricity bill). The table below assumes these customers have not changed the overall amount of energy they consume – only the time they consumed it. If they also reduced the amount of energy they used, they would be able to achieve lower bills. It is important to note these examples are illustrative only and not every customer will make savings with cost-reflective tariffs. Actual cost impacts will depend on a variety of factors, such as how, when and how much electricity each customer uses.

Who	**Lynette and Ian** Pensioners from Shellharbour **1,600kWh/year** **Without solar**	**The Hanlons** Renewable energy family from the Blue Mountains **1,800kWh/year** **With solar**	**The Williams** Family of four from Cranebrook **4,800kWh/year** **With solar**	**The Patels** Young family from Seven Hills **6,000kWh/year** **Without solar**	**Downtown Dry Cleaning** Dry cleaner from Parramatta **13,100kWh/year** **Without solar**	**Jamberoo farmer** Producer from Jamberoo **13,500kWh/year** **With solar**
Current flat tariff	**$355**	**$371**	**$656**	**$758**	**$1,572**	**$1,468**
Cost-reflective tariff	$8 saving	$13 cost	$7 cost	$21 saving	$356 saving	$21 saving
Change in timing of energy use away from peak periods	$4 saving	$6 saving	$13 saving	$14 saving	$3 saving	$28 saving
Total impact of cost-reflective tariff and change in timing of energy use	**$12 saving** **$343**	**$7 cost** **$378**	**$6 saving** **$650**	**$35 saving** **$723**	**$359 saving** **$1,213**	**$49 saving** **$1,419**

Overview

Chapter 1

1.1 Purpose of the Tariff Structure Explanatory Statement

Endeavour Energy is submitting this Tariff Structure Explanatory Statement (TSES) to the Australian Energy Regulator (AER) as an accompanying document for the Tariff Structure Statement (TSS) that Endeavour Energy has also submitted to the AER in accordance with the requirements of the National Electricity Rules (the Rules).

The purpose of the TSS is to present our proposed tariffs and demonstrate our compliance with the Rules, and the purpose of the TSES (this document) is to provide supplementary technical information that further describes how tariffs are designed and how we propose to set prices in the 2024-29 regulatory control period (RCP).

This TSES should be read in conjunction with the TSS itself. Both the TSS and TSES form part of our Proposal for the 2024-29 regulatory control period and should be read in conjunction with the rest of the Proposal.

1.2 Structure of the Tariff Structure Explanatory Statement

Table 1: Structure of this document

Chapter	Title	Purpose
Chapter 2	Our operating environment	This section describes changes in how customers use our network.
Chapter 3	Customer engagement	This section outlines the process we have undertaken in engaging with our customers and responds to the feedback we have received through stakeholder consultation.
Chapter 4	Key challenges and opportunities	This section describes the key drivers and considerations of our tariff strategy in this regulatory control period are discussed in this section.
Chapter 5	Our network tariff reforms	This section explains the proposed changes to our network tariffs over the next regulatory period.
Chapter 6	Impact of proposed tariffs on customers	This section sets out our analysis of the impact of proposed changes to our tariffs on those customers to whom such changes will apply.
Chapter 7	Compliance with pricing principles	This section sets out how our proposed tariff structures comply with the Pricing Principles set out in the Rules.
Appendix 1	Glossary	This provides a definition for some key terms used throughout this TSES.
Appendix 2	Allocation of customers to tariff classes	This appendix provides a summary of our tariff classes and how customers are allocated to these tariff classes.
Appendix 3	Proposed charging parameters	The structure and charging parameters for our tariffs are set out in this appendix.
Appendix 4	Compliance checklist	This section sets out a checklist that identifying where each of the TSS Rule Requirements are met in the TSS and this TSES.

Our Operating Environment

Chapter 2

This section explains the contextual environment in which Endeavour Energy operates and in which this TSS and wider regulatory proposal have been developed. We describe:

- our role in the broader electricity supply chain;
- our physical electricity network;
- the regulatory and policy landscape in which we operate;
- the changes in behaviour and technology choices by our customers;
- our evolving role in managing the network; and
- the implications of these factors for network tariffs.

2.1 Our position in the electricity network

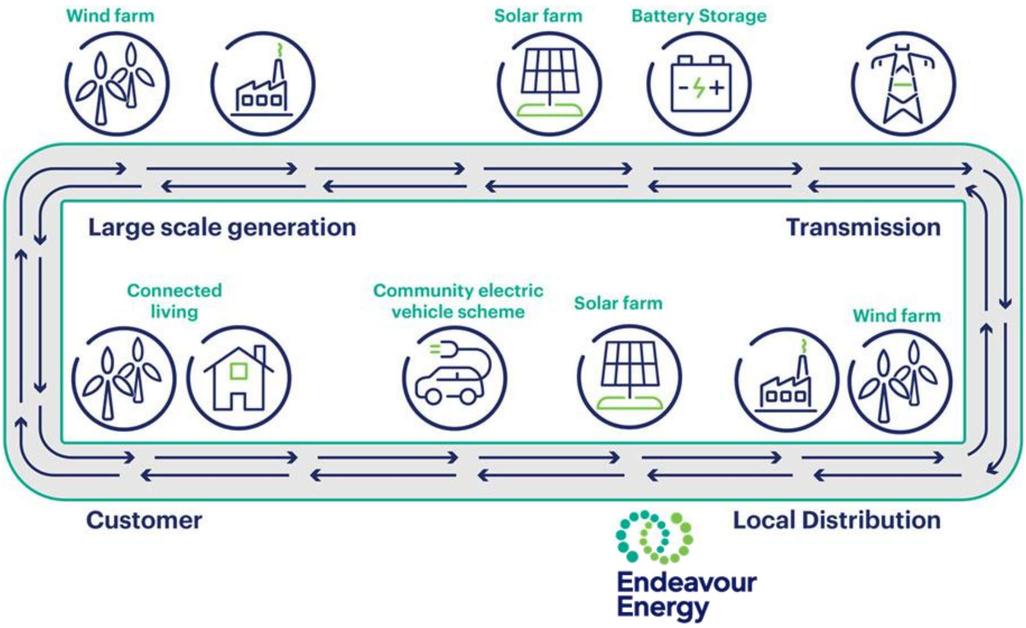
Endeavour Energy operates as a distribution network service provider (DNSP) in the National Electricity Market (NEM).

Traditionally, the role of a DNSP is to provide an electricity transport system for producers and end-users, such as homes and small businesses, from the higher voltage transmission network and within local networks.[1] The sharp rise in installations of customer energy resource (CER) assets such as, solar PV and batteries has altered our role as a network to now handle generation from these customer energy sources back into the wider network. Moving forward, our role as a network will continue to transition to a two-way flow network.

We perform our role according to extensive obligations, standards, conditions and requirements, particularly in relation to customer and community safety, and the security and reliability of supply.

Our role in the electricity network is presented in Figure 1.

Figure 1: Endeavour Energy's position in the electricity network



[1] The transmission network service provider (TNSP) for Endeavour Energy's network is Transgrid.

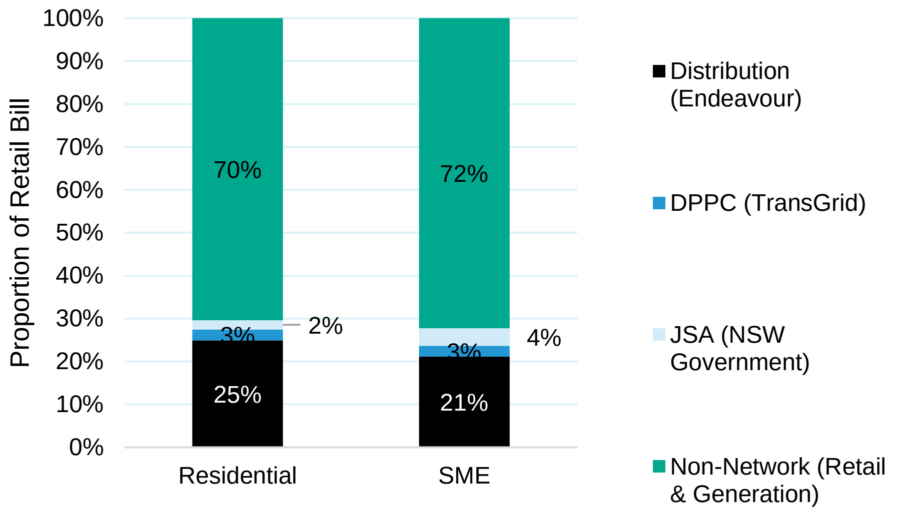
Each distinct component of the electricity supply chain incurs associated costs, which are recovered through fees paid by network users importing electricity from and exporting electricity to the grid. Network users typically engage retailers to source and provide electricity on their behalf, which incurs further retail costs to be added to the final price.

Only around a quarter to a third of a customer's total electricity bill reflects our AER-approved costs (the distribution component).

The cost of generation and retail services provided by third parties, over which Endeavour Energy has no control, make up over 70 per cent of a customer's electricity bill, on average.

The average breakdown of a typical residential and small business electricity bill in Endeavour Energy's network is presented in Figure 2.

Figure 2: Endeavour Energy's costs make up approximately 25% per cent of the average electricity bill.



Source: Endeavour Energy and Origin Energy.

We are also responsible for passing on transmission costs and jurisdictional schemes costs from the NSW Government, e.g. climate change fund levy, and legacy metering costs, which, together with our distribution 'network costs', make up the total network bill.

2.2 Our network

Our network services communities with some of the highest cultural and language diversity in Australia across the lands of the traditional custodians – the people of the Dharawal, Dharug, Gundungarra, Wiradjuri and Yuin nations. We recognise first peoples' continuing connection to Country, cultures and community. We pay our respect to elders past and present.

Figure 3: Endeavour Energy's network area

Endeavour Energy manages a $7.7 billion electricity distribution network for 1,080,000 customers, or 2.6 million people, in households and businesses across an area spanning 25,000 square kilometres in Sydney's Greater West, the Blue Mountains, Southern Highlands, Illawarra and South Coast of NSW.

We serve:

- 2.7 million people;
- 20,000+ new customers per year;
- 225,000 exporting customers;
- 32,000 life support customers.

Our network covers some of the largest and fastest growing regional economies in the state with Western Sydney projected to accommodate an additional 700,000 residents by 2041[2] The challenges associated with managing growth across our network are discussed further in sections 2.2.1 and 2.2.2 below.

In addition to population growth, our customers have the third highest energy density and demand density in the NEM. This means that our customers consume a relatively high amount of energy, particularly during peak times (4pm to 8pm). This is largely due to a combination of higher summer temperatures (often up to 10 degrees higher than the Sydney CBD) and energy-intensive economic activity.

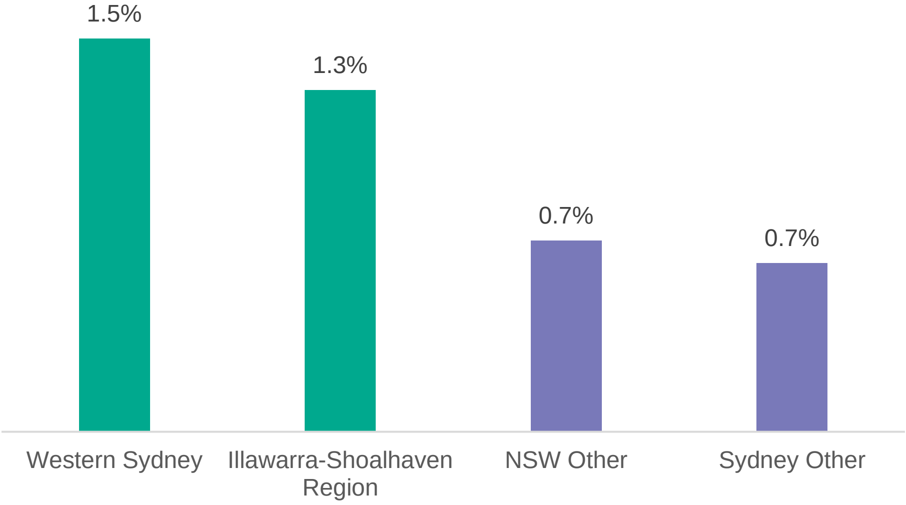
By June 2022, approximately 225,000 customers had connected their own small scale renewable generation (mostly solar panels) to the network, representing a cumulative capacity of around 1GW. This is an increase of 105,000 (88%) customers and 670MW (203%) in additional capacity over the five years from June 2017. The increased uptake of CER is presenting both challenges and opportunities, which we discuss further in section 2.5.

2.2.1 We operate in an area with substantial forecast growth

Greater Western Sydney is the focal point of future population and industrial growth in NSW. This strategic expansion, supported by the NSW government, is expected to grow at double the annual rate of the rest of metropolitan Sydney, as indicated in Figure 4.

[2] NSW Department of Planning

Figure 4: Population growth in key franchise areas is significantly larger than other areas in NSW (2022-2041)



Source: NSW Department of Planning

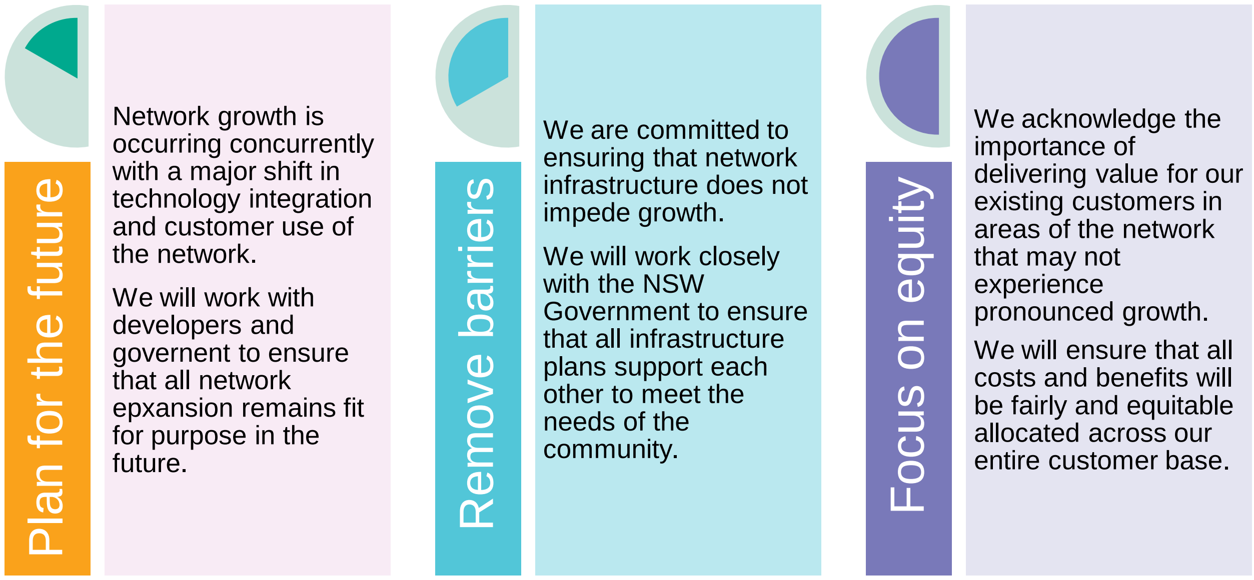
Current projections indicate that Western Sydney will accommodate:

- an additional 290,000 dwellings;[3]
- a new airport and surrounding 'aerotropolis';
- new and rejuvenated manufacturing areas; and
- a science park.

This significant growth in Western Sydney has shaped our current and expected future operational landscape. Our strategy for accommodating this rapid growth is presented in Figure 5.

[3] NSW Department of Planning

Figure 5: Growth accommodation strategy



2.2.2 More Greenfield developments will increase the number of embedded networks

Embedded networks are private networks that serve multiple premises and are located within, and connected to, our distribution network through a single connection point.

The defining feature of an embedded network for tariffs is that we have only one customer (at the single connection point), even though there are many different individuals or businesses that sit behind that connection, which are often referred to as 'child' connections.

Greenfield developments often choose to supply electricity to the individual connections within the development through an embedded network.

Apartment buildings, industrial parks and shopping centres also frequently connect to our network in the form of an embedded network.

The expected increase in greenfield developments across our network is therefore expected to result in a similar increase in embedded networks.

Under the Rules, any party that engages in the supply of electricity must either be a registered network service provider, like Endeavour Energy, or gain an exemption from the AER.[4] The AER keeps a log of these network exemptions which shows that approved network exemptions in NSW increased from 102 in 2013 to a peak of 356 in 2020.[5]

On average, we forecast 21,000 new residential dwellings will be built on our network each year in the 2024-25 and 2028-29 period. We anticipate that an increasing proportion of these households will connect via an embedded network given:

- the relative ease of connecting geographically proximate dwellings as a single network connection; and
- the current network bill arbitrage opportunity between large and small connection tariffs.

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[4] AER, *Network exemptions*, available at https://www.aer.gov.au/networks-pipelines/network-exemptions.

[5] AER, *Public register of network exemptions*, available at https://www.aer.gov.au/networks-pipelines/network-exemptions/public-register-of-network-exemptions

While embedded networks can provide benefits to the customers that sit within them, we are concerned that our current network tariffs and assignment policy result in these customers making an inappropriately low contribution to recovering the cost of our existing network, which is unfair for all other customers.

2.3 Relevant New South Wales Government policy

The NSW Government is committed to reducing emissions by 50 per cent between 2005 and 2030, with a net-zero target set for 2050.[6] Underpinning this renewable energy target is the NSW Electricity Infrastructure Roadmap (the Roadmap) which aims to deliver an additional 12 GW of renewable generation and 2 GW of storage in NSW by 2030.[7]

We understand that the NSW Government will recover some of the cost of these projects through an additional cost component that will be passed through to customers by distribution networks in NSW.[8] The cost remains uncertain, but it is likely to materially increase electricity bills in NSW.

We have highlighted this uncertainty in our engagement activities and have consulted extensively with the NSW Government on reforms to implement the Roadmap. Our position remains that the Roadmap costs and benefits should be transparently communicated to NSW electricity customers.

The NSW Government has also identified hydrogen as a significant contributor to Net-Zero emissions. A hydrogen industry, for both domestic consumption and international export, may also add considerable load to the electricity network and hence may influence the aggregate load characteristics of our network.

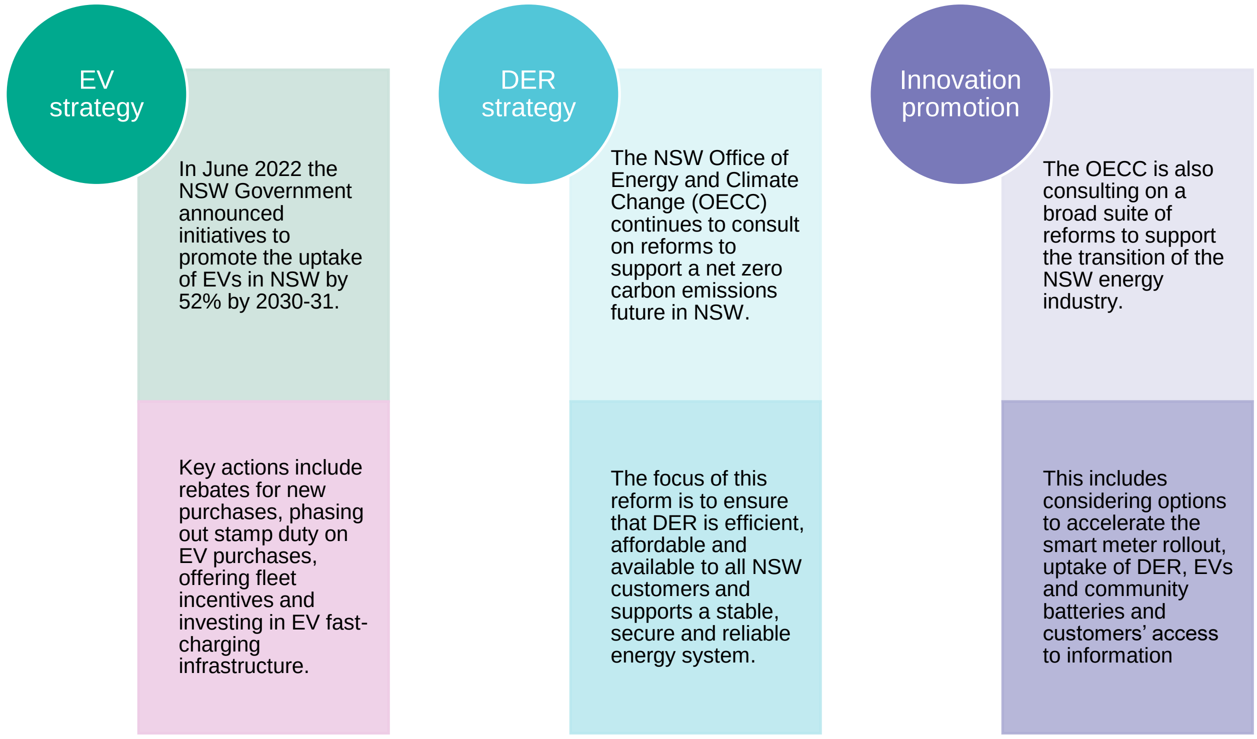
In addition to the Roadmap and hydrogen strategy, the NSW Government is currently consulting on a number of other reforms, presented in Figure 6.

[6] Department of Planning, Industry and Environment (NSW), *Net Zero Plan Stage 1: 2020-2030 Implementation Update*, September 2021, p 4.

[7] Department of Planning, Industry and Environment (NSW), *NSW electricity infrastructure roadmap | Building an energy superpower – detailed report*, November 2020, p 29.

[8] Department of Planning, Industry and Environment (NSW), *NSW electricity infrastructure roadmap | Building an energy superpower – detailed report*, November 2020, p 29.

Figure 6: Ongoing NSW Government energy policy reforms



2.4 The regulatory landscape is undergoing rapid evolution

There have been a number of regulatory reviews, reforms and rule changes since our last TSS. This section summarises the key changes in regulatory changes relating to our tariff strategy.

2.4.1 Two-way pricing and incentives

In August 2021 the AEMC published its final determination on the export pricing rule change. The key features of the reform package are:[9]

- updating the regulatory framework to clarify that distribution services are two-way and include export services, and as such the current rules relating to distribution services apply to export services;
- providing incentives for efficient investment in, and operation and use of, export services – including by requiring the AER to regularly calculate the values of CER curtailment to guide investment and regulatory decisions and providing protections to customers from inefficient zero export limits; and
- removing the prohibition on distribution businesses pricing for export services – allowing for both positive and negative charges.

The key requirements of this rule change as it relates to the regulatory process and this TSS are:[10]

- requiring Endeavour Energy to develop and consult on a two-way tariff transition strategy, which will outline our intended stakeholder and customer engagement plan and transitional measures to phase-in export pricing over time;

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[9] AEMC, *Access, pricing and incentive arrangements for distributed energy resources | Final determination,* August 2021, p 5.

[10] AEMC, *Access, pricing and incentive arrangements for distributed energy resources | Final determination,* 12 August 2021, pp 67-68.

- strengthening the consultation requirements through the regulatory and TSS processes, building on the customer safeguards already built into the pricing framework;
- introducing transitional arrangements to protect customers that have already made significant investments by prohibiting the assignment of existing CER customers to export tariffs before 1 July 2025 (unless requested by the customer); and
- requiring Endeavour Energy to offer a basic export level without charge, whereby a retail customer can export to the distribution network up to this level at no additional charge for the next two regulatory periods.

Importantly, the final rule does not mandate export pricing. We explore the challenges and opportunities associated with export pricing in section 4.2 and present our two-way tariff transition strategy in section 5.3 and chapter 6 of our TSS.

2.4.2 CER integration expenditure guidance

The AER has reviewed its assessment framework for CER integration expenditure by DNSPs. While the AER has acknowledged that DNSPs need to invest in network expenditure to facilitate the increasing penetration of CER and the changing ways customers want to use the network,[11] the assessment of CER integration expenditure is not explicitly addressed by the AER's existing guidance.[12]

The AER proposes that DNSPs explain how CER integration is managed through the different elements of their regulatory proposal,[13] including, among other factors, how their proposed pricing structures will manage the demand for consumption and export services and make best use of existing network hosting capacity.

By way of example, if Endeavour Energy were to implement export charges, then the CER integration expenditure plan should account for the forecast change in customer behaviour brought about by two-way tariffs and incorporate the impact of this changed network use on future network expenditure requirements.

2.4.3 Changes to ring-fencing guidelines

In November 2021, the AER finalised amendments to the distribution ring-fencing guidelines to support and enable the adoption of stand-alone power systems (SAPS) and grid-connected storage devices.[14] Both of these technologies may potentially play a pivotal role in the energy transformation.

There appears to be 'limited evidence that third party providers are currently willing or able to offer SAPS services'.[15] Under the ring-fencing guidelines, we are permitted to provide non-distribution services, i.e., generation services, to a SAPS where it is the best interest of consumers and the total revenue we earn from these services is capped.[16]

We have identified several potential SAPS sites in our network that could be developed in the coming years.[17] These SAPS will support customers in the worst served areas of our network.

We can apply to the AER for a waiver to provide an energy storage device that sets out whether the likely benefit to our customers exceeds the costs and so is improves outcomes for our customers.[18]

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[11] AER, *Assessing DER integration expenditure | Consultation paper*, November 2019, p 14.

[12] AER, *DER integration expenditure guidance note*, June 2022, p 8.

[13] AER, *DER integration expenditure guidance note*, June 2022, p 11.

[14] AER, *Ring-fencing guideline | Electricity Distribution | Version 3*, November 2021, p ii; and AER, *Updating the ring-fencing guidelines for stand-alone power systems and energy storage devices | Issues paper*, November 2020, p 7.

[15] AER, *Draft electricity distribution ring-fencing guideline | Explanatory statement*, May 2021, p 18.

[16] AER, *Ring-fencing guideline | Electricity Distribution | Version 3*, November 2021, pp 7-8.

[17] ENA, *Updating the electricity distribution ring-fencing guideline – response to the AER issues paper*, 18 December 2020, p 7.

[18] AER, *Ring-fencing guideline | Electricity Distribution | Version 3*, November 2021, pp 7-8, 16-17.

This change to the regulatory treatment can assist with the transition of grid-connected storage devices onto our network. We are therefore considering how best to design tariffs for storage devices to incentivise connection to our network.

2.5 Our customers are using the network in new and innovative ways

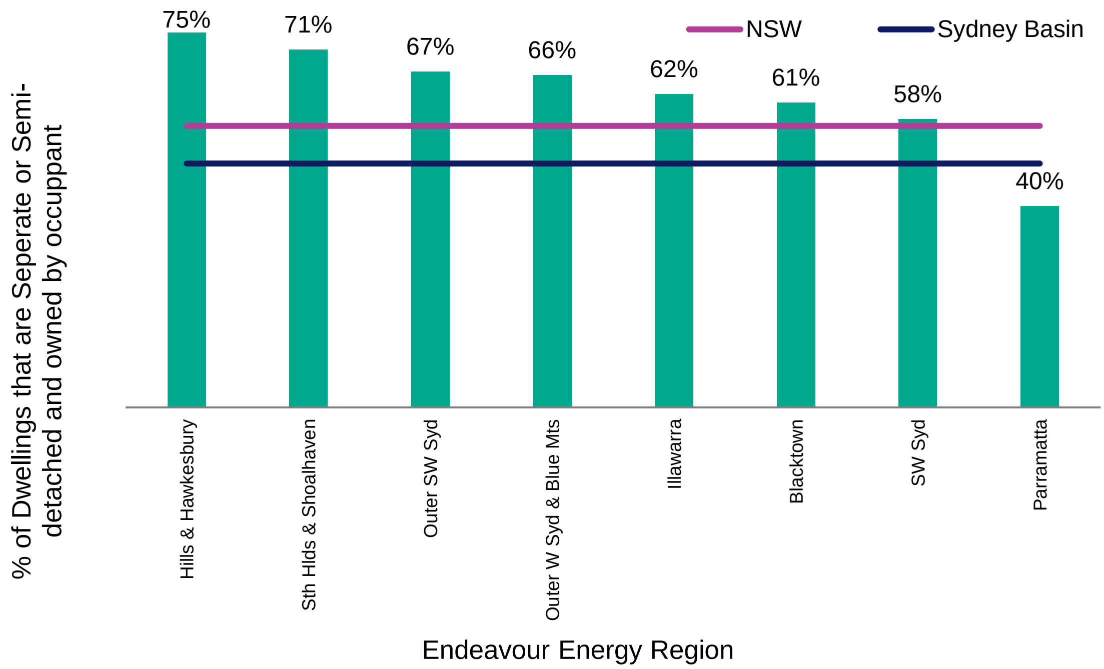
Our customers are constantly striving to take further control of their electricity usage, reduce their bill by helping to lower our costs and play a bigger role in the energy market transition to clean energy. This has seen a significant increase in the installation of CER assets behind the meters of our small-scale customers.

This technology, and the network services that accompany their integration, is shifting our role as a network from a one-way flow supply to a platform of two-way energy sharing. As we enhance our capabilities as an energy trading platform, our role will continue to shift from traditional distributor to Distribution System Operator (DSO).

Figure 7 indicates that our residential customers have opportunities to invest in CER technology due to the relatively large proportion that own separate and semi-detached properties.

As technology improvements drive down the costs of CER assets and our network tariffs provide further value for our customers, we envision that CER technology will become more accessible for all customers across our network.

Figure 7: The opportunity to invest in CER for customers in NSW

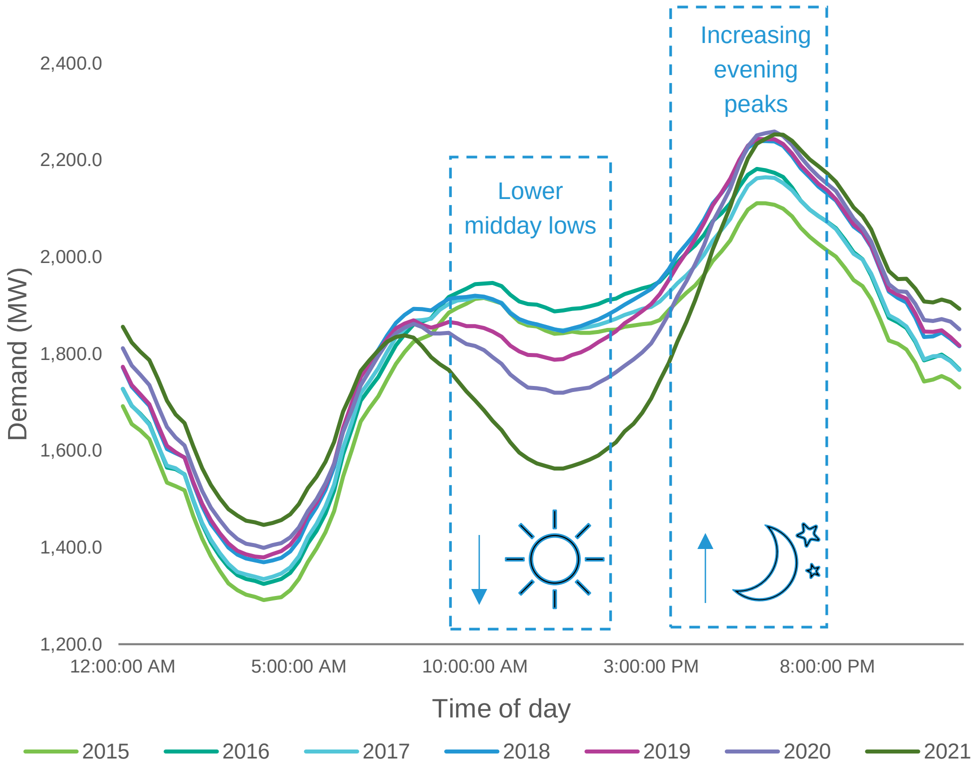


Source: 2021 ABS Census

However, the proliferation of CER assets has changed, and will continue to change, the daily profile of electricity demand on our network. As shown in Figure 8, recent trends our aggregate load profile include:

- lower demand in the middle of the day;
- higher demand in the evening peak; and
- significant ramping of load between these two periods.

Figure 8: Impact of solar PV installations on Endeavour Energy's average network demand

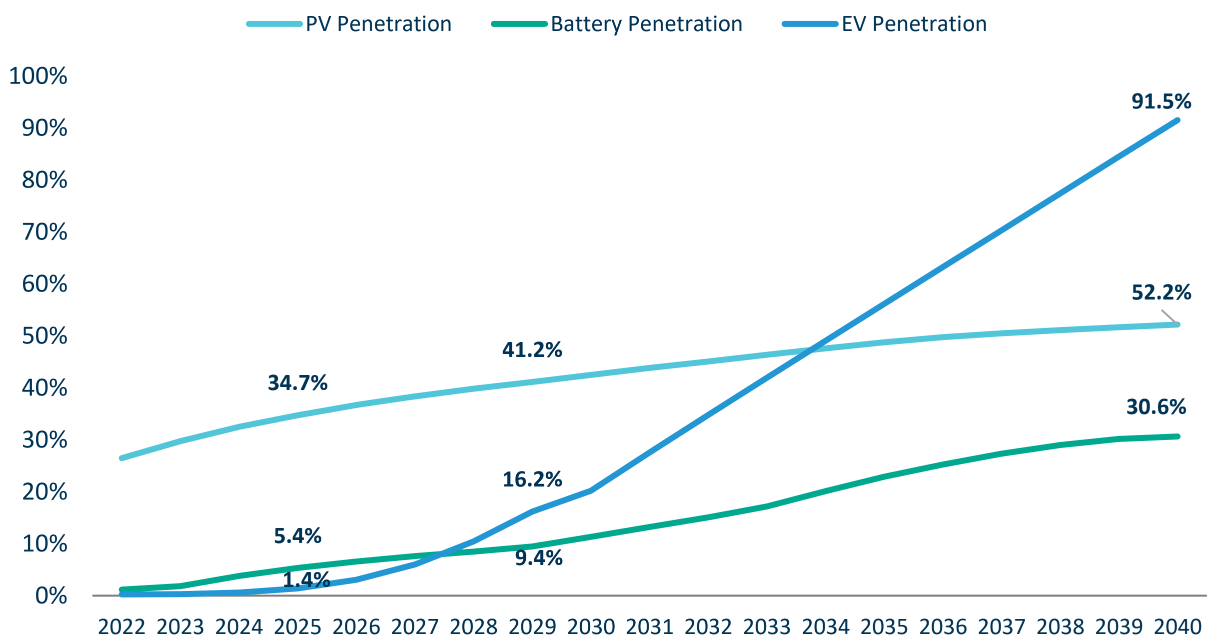


In response to the prevalence of emerging technologies, we are focused on finding ways to equitably deliver customer choice to install CER assets that best suit their needs while also incentivising customer behaviour and investments that support the safe, reliable and secure operation of our network.

Efficient tariff structures and price signals provide customers with the information they need to identify whether an investment in CER is the lowest-cost solution for meeting their energy needs.

In the remainder of this section, we detail a number of these CER technologies, including solar PV, EVs and behind-the-meter batteries which are the three most prevalent CER technology types, as shown in Figure 9.

Figure 9: Forecast uptake of solar PV, EVs and batteries

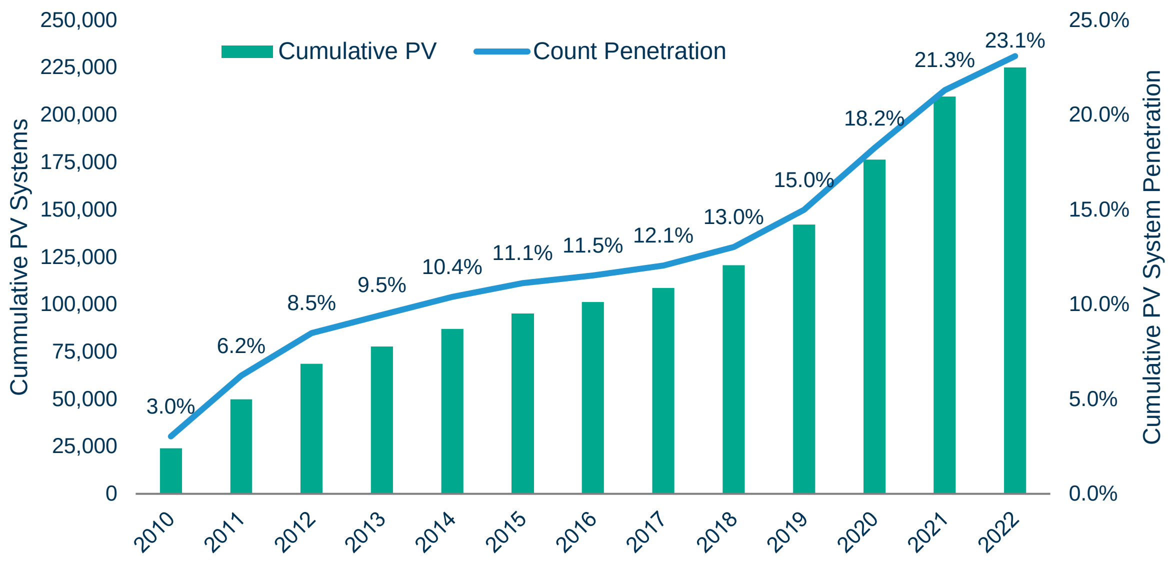


2.5.1 Solar PV

Currently, 23% of Endeavour Energy's residential customers have solar PV systems with a cumulative capacity of 1GW.

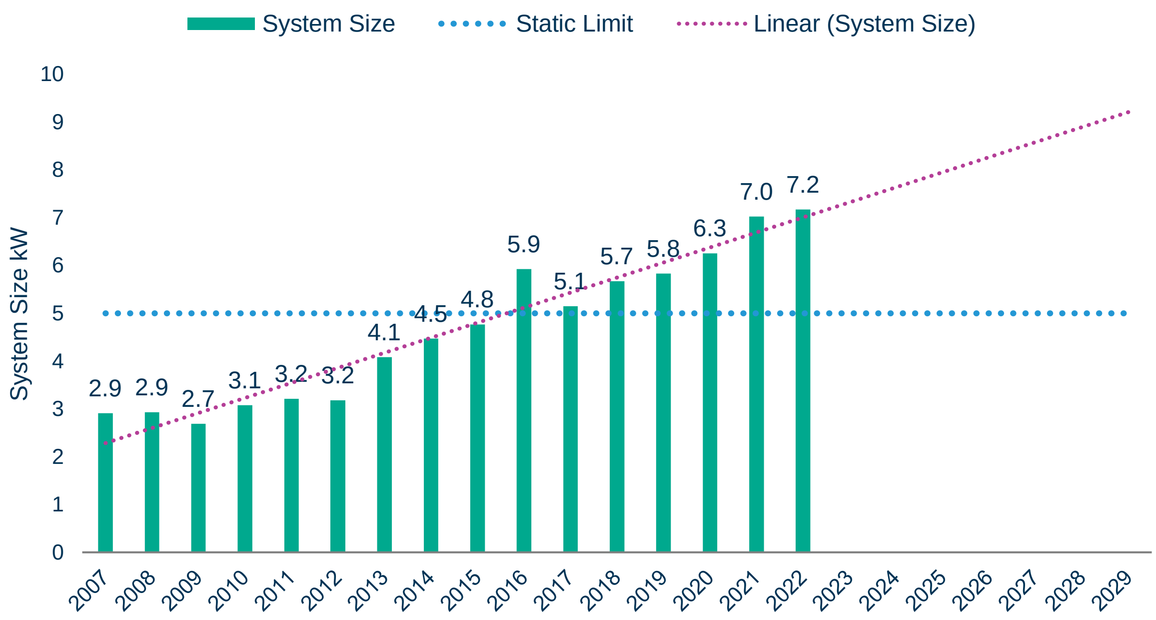
The growth in residential solar PV take-up is illustrated below.

Figure 10: Residential solar PV take-up



In addition to more customers adopting solar PV, customers are investing in larger and larger systems.

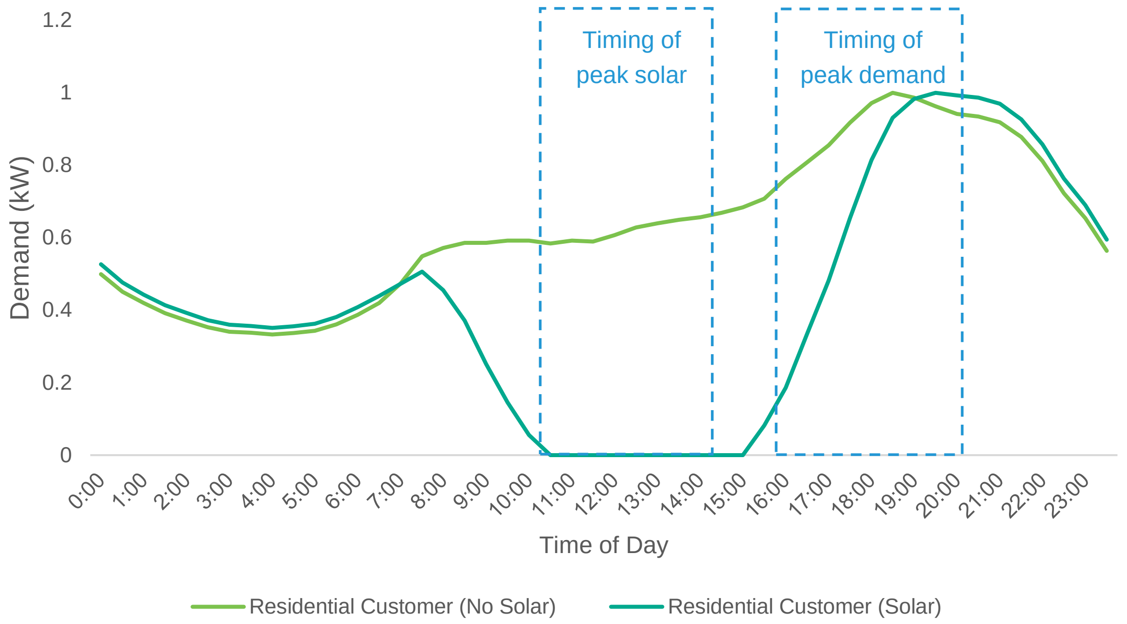
Figure 11: Average residential solar system size and trend



Further, around 14 per cent of commercial customers have solar PV systems, with a cumulative capacity of more than 200MW. Endeavour has seen significant interest towards commercial solar with major companies looking to install rooftop solar on their buildings in the order of 1-10MW in size. Wester Sydney Airport is just one example of this with the proposed solar farm expected to reach up to 50MW. Multiple major developers within the Aerotropolis are already engaging with us to explore 100% solar communities across 5 of the new Zone Substations planned for construction.

Solar PV assets are the most common way our customers engage in two-way flows and energy sharing, by export excess solar generation back onto our network for other customers to consume. However, output from solar PV systems is typically largest during the middle of the day, when system-wide demand is often low, as shown in Figure 12.

Figure 12: Generation from solar PV does not coincide with system peak demand



This misalignment between peak network demand and peak solar generation means that increased solar PV installations and low levels of load contribute to a widening of the imbalance between supply and demand, which can lead to localised voltage surges across the network. These voltage management issues can cause:

- damage to network equipment;
- trips and faults; or
- a temporary shutdown of a customer's solar PV system to restore voltage to a safe level.

Potential solutions to the issues caused by increased solar PV uptake include:

- imposing a limit on the ability for a customer to export onto the network;
- charging a customer for their exports to the network;
- providing innovative network services, such as community batteries; and
- incentivising customers to explore customer-led non-network solutions, such as behind-the-meter batteries.

As a matter of principle, we are committed to avoiding the need to curtail customer's exports and addressing equity concerns that could arise as local exports approach the capacity of our existing network to facilitate exports.

In this context, we acknowledge that 'equity' for our customers includes:

- allowing new solar customers to access the benefit streams of their investment; and

- ensuring that network costs are fairly allocated to all customers, i.e., does not preference one type of customer over another.

2.5.2 Energy storage

Small scale energy storage devices (e.g., behind the meter batteries) will be a pivotal technology in the energy transition. While we expect a near doubling of behind the meter batteries over the 2024–29 regulatory control period, we expect only 9.4 per cent of residential customers to install a behind the meter battery by 2029.

Energy storage devices connected to the low voltage network, including community batteries and behind the meter batteries, can flatten the demand profile across the middle of the day and the evening peak by shifting exports from solar generation from the middle of the day to the evening, when they can assist in managing peak demand.

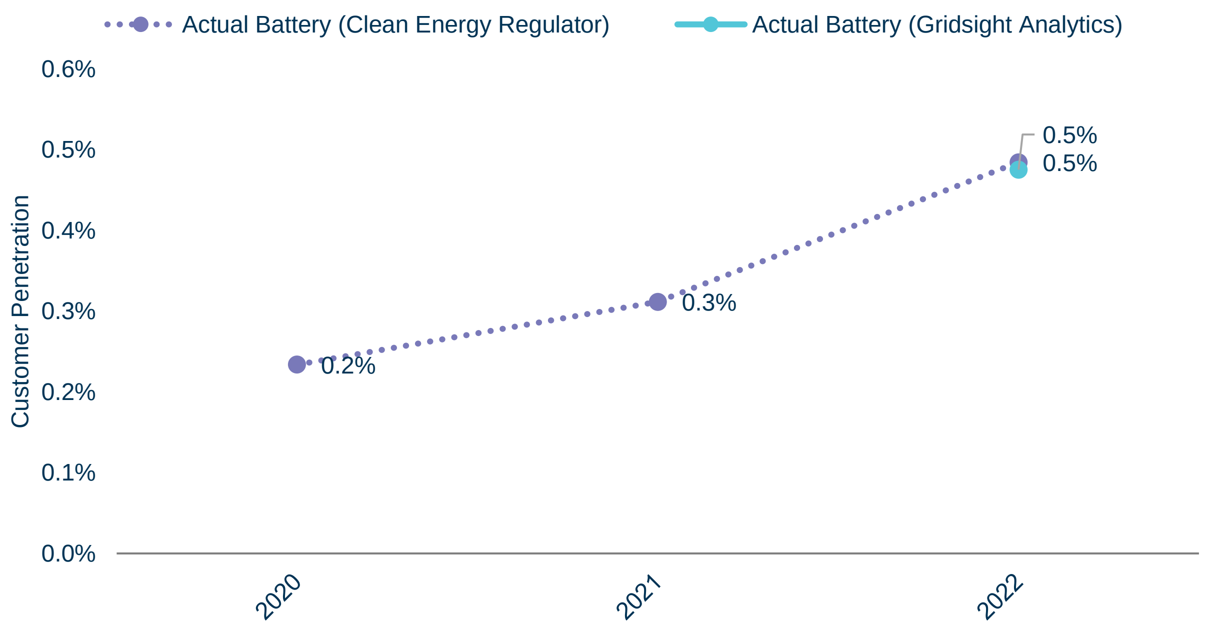
Large scale storage technology, such as grid-connected batteries and pumped hydro storage, facilitates a more dynamic approach to managing aggregate demand and supply imbalances. In the same manner as low voltage applications, large scale storage is pivotal in supporting higher penetration of renewable generators.

We have only recently begun the collection of Battery System applications data for behind the meter battery systems. This makes it difficult to determine the growing penetration on the network. To assess the current penetration of battery systems we have used two methods:

- smart meter data analytics through the Gridsight platform we have determined that as of June 2022, 0.5% of solar customers have a battery system.
- the Clean Energy Regulator's battery dataset for NSW and applied a pro rata representative of Endeavour Energy's share of NSW electricity customers. Further, we have adjusted the 2022 numbers to pro rata for year-end 2022.

There is strong alignment between these two data sources for actual battery take-up as shown below.

Figure 13: Battery penetration Clean Energy Regulator vs smart meter detected batteries



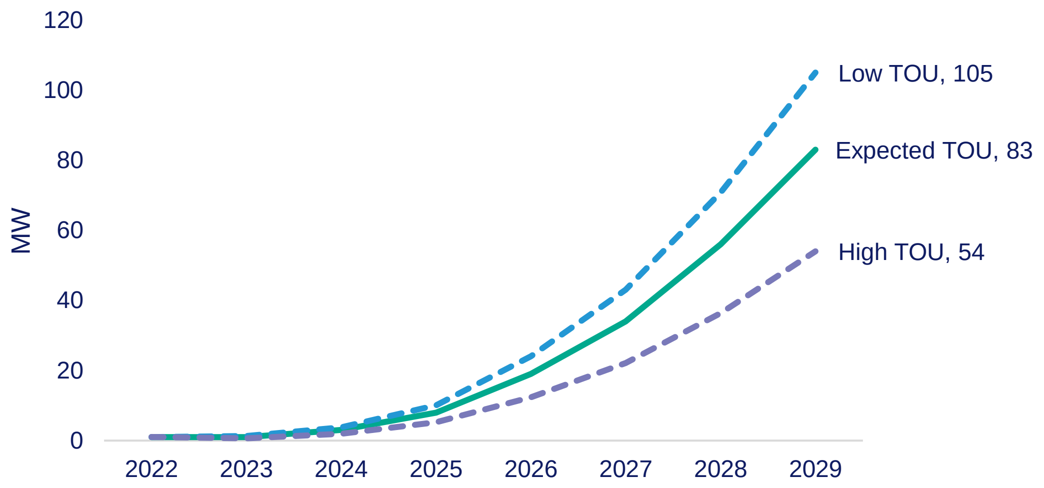
2.5.3 Electric vehicles

By 2029, we expect 16.2 per cent of all households across our network to have an EV, up from 1.4 per cent currently. The electrification of commercial fleets and public transport is also likely to increase in the near future.

We are focused on preparing our network for the rapid rise in EVs in the near future. As a large and flexible load, EV charging has the potential to significantly impact the network demand profile. Conversely, EVs represent a valuable opportunity to help flatten load as a mobile storage device, although this application will require significant improvements in digital operating capability and third-party involvement.

Incentivising the charging of residential, commercial and dedicated public station EV load to occur during periods that provide network support will maximise the value of transport electrification for all customers. As shown in Figure 14, EVs are estimated to contribute around 83 MW to system peak demand by 2029 under our expected tariff and controlled load approach. This value could increase to 105 MW if our tariff strategy is less effective at shifting EV charging outside of the evening peak period.

Figure 14: Expected impact of electrification of vehicles



2.5.4 Demand response and flexible load shifting

Demand response is the voluntary shift in a customer's use of electricity to ease constraints and provide network support.

Demand response represents a growing opportunity to manage periods of peak demand and periods of high solar exports by shifting load from peak periods to low demand periods. This opportunity hinges on the ability for customers to maintain a portion of their load that is flexible or discretionary, such as:

- water heaters, air-conditioning systems, pool pumps and possibly EV charging for residential customers; and
- flexible production for business and industry customers.

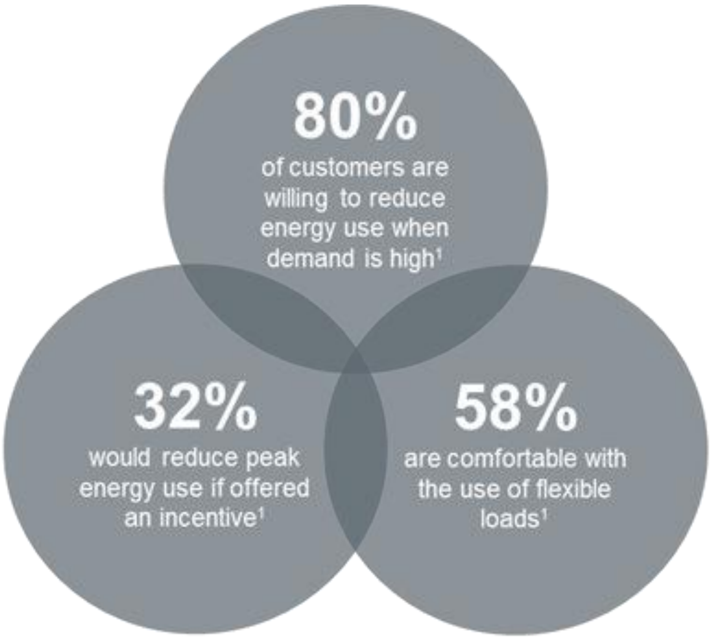
Our customers aspire for the energy transition to be a 'win-win' outcome in which:

- our network provides clean energy; while
- personal savings are achieved through more efficient technology and increased choice and control of their electricity usage.

Demand response is a simple way for our customers to reduce their network bill while also contributing to the energy transition, thereby presenting a 'win-win' opportunity for the transition to clean energy.

Figure 15 shows that our customers are willing to refine their behaviour and use of the network to provide network support. This presents an opportunity for Endeavour Energy to design tariffs that incentivise load shifting and make it easier for customers to control the flexible component of their load.

Figure 15: Our customers have indicated that they would respond positively to the option to provide demand response



> *"I would like to take a little bit more control of my electricity. I want it broken down so I can be a little more in control. In an app [so I know] fridge uses this, washing machine uses that."*
> \- Customer quote, SEC Newgate Research

2.5.5 Microgrids and stand-alone power systems

Microgrids and SAPS can present a more cost-effective solution than investments that connect the relevant customers to the broader network. In some cases, these systems can be completely separated from the rest of our network, thus mitigating the need for significant augmentation or replacement of network and connection assets to these areas.

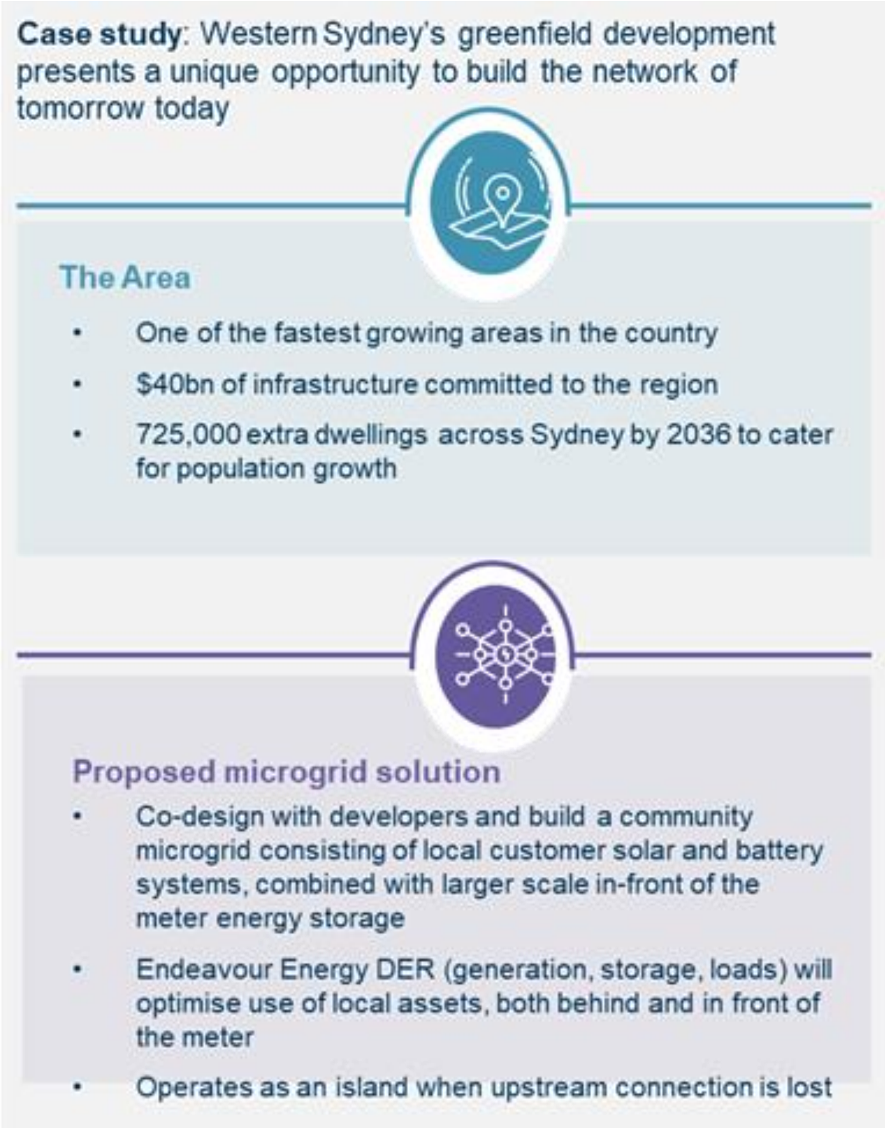
Microgrids and SAPS can therefore provide a lower cost alternative to traditional network design and give rise to a more modular network with localised areas that are able to remain self-sufficient.

The value that can be derived from microgrids and SAPS arises from their:

- increased commercial viability due to the decreasing cost of distributed generation and storage technologies, as well as the increasing costs of providing traditional network connection; and
- avoid the need for long and stringy network connections, which reduces the risk to the safety and reliability of the network.

Microgrids and SAPS can offer certain communities a chance to help co-design their energy system, specifically creating elements for their unique values and needs. Any use of these technologies will need to align with the guidance from the AEMC and AER regarding appropriate distributor-led use as described in section 2.4.3.

Figure 16: Microgrids can provide solutions in Greenfield developments areas



2.6 The importance of tariff reform in our regulatory proposal

The material presented in section 2.5 suggests that we are in the relatively early stages of the journey towards a 'Future Grid', in which our role as a network operator and our network itself will undergo a significant change.

In this section, we demonstrate how our future tariff strategy is integrated with our network planning to ensure that our forecast expenditure plan reflects the use of the network our tariffs incentivise.

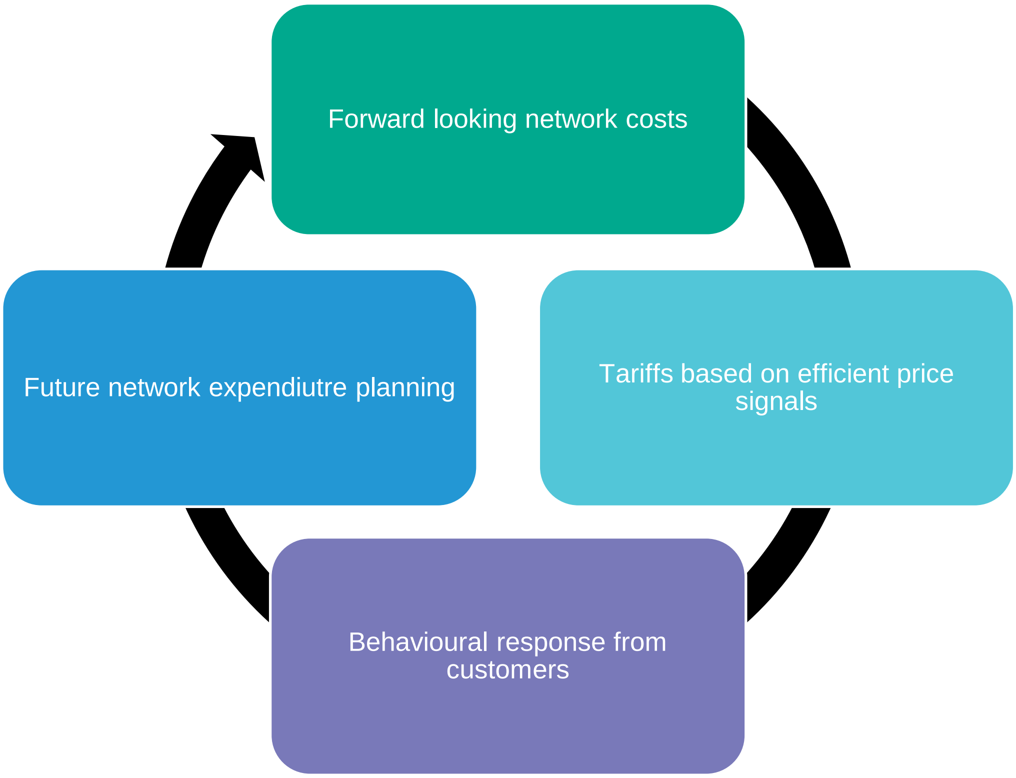
2.6.1 Quantifying the reduction in future network expenditure from customer responses to our tariff reform

In preparation for the submission of a CER integration expenditure strategy to support the implementation of two-way tariffs, the AER has encouraged DNSPs to 'use the right balance of price signals and investment' to reduce network costs for customers.[19] As part of our broad regulatory proposal, we have ensured alignment between our tariff strategy and network expenditure plan.

Cost-reflective tariffs can help unlock the value of consumer driven non-network solutions that provide reliable and cost-effective two-way flow network services. Our cost-reflective tariffs ensure our tariff strategy reflects the future costs required to facilitate increased two-way flows on our network.

Efficient price signals throughout the day encourage behaviour by customers that lowers our network expenditure in the future. In this sense, the tariff strategy is integrated with the wider network planning process as shown in Figure 17.

Figure 17: The relationship between tariff strategy and network expenditure planning



2.6.2 Lower future maximum import demand will reduce network augmentation requirements

In the past, Endeavour Energy's future network expenditure plan was primarily focused on supporting the future level of maximum import demand.

Our proposed future expenditure plan takes account of augmentation to support expected future network growth and replacement of existing parts of the network. The forecast of maximum import demand dictates the need for growth related expenditure and potentially the replacement profile for assets with deteriorated performance at higher demand levels. As such, maximum import demand plays an important role in the network expenditure planning process.

Endeavour Energy's tariff strategy is expected to reduce maximum import demand across the network by almost one per cent over the next ten years. Moreover, in areas of the network without large volumes of new

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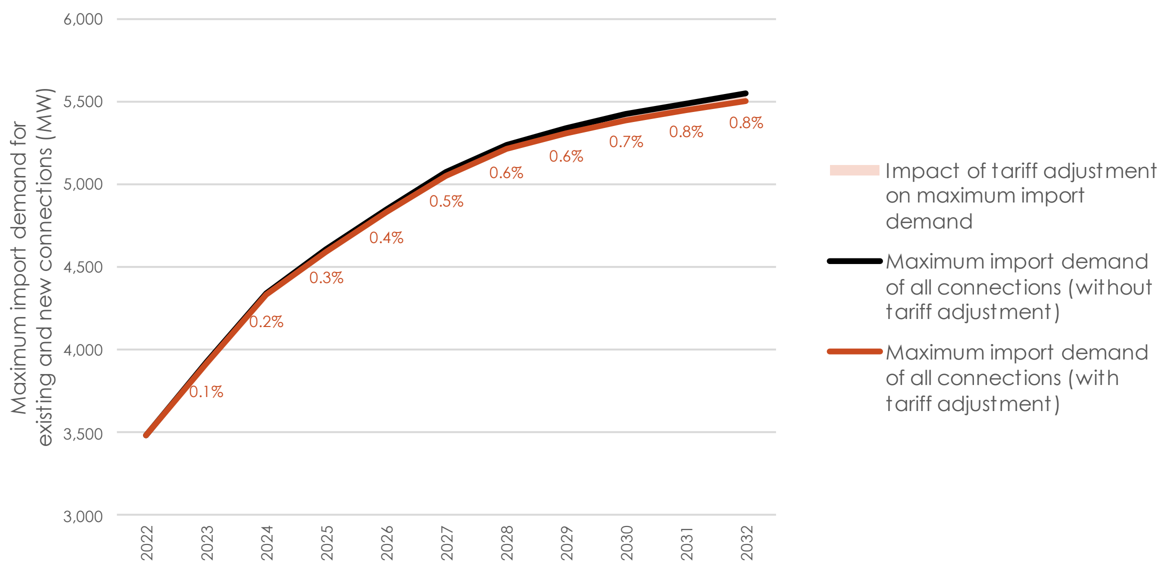
[19] AER, *Explanatory note – Tariff reform and integrating DER,* September 2021, p 1.

connections the reduction in maximum import demand in response to the tariff strategy is around twice as large, exceeding 1.5 per cent by 2032.

Figure 18: Forecast of network-wide maximum import demand



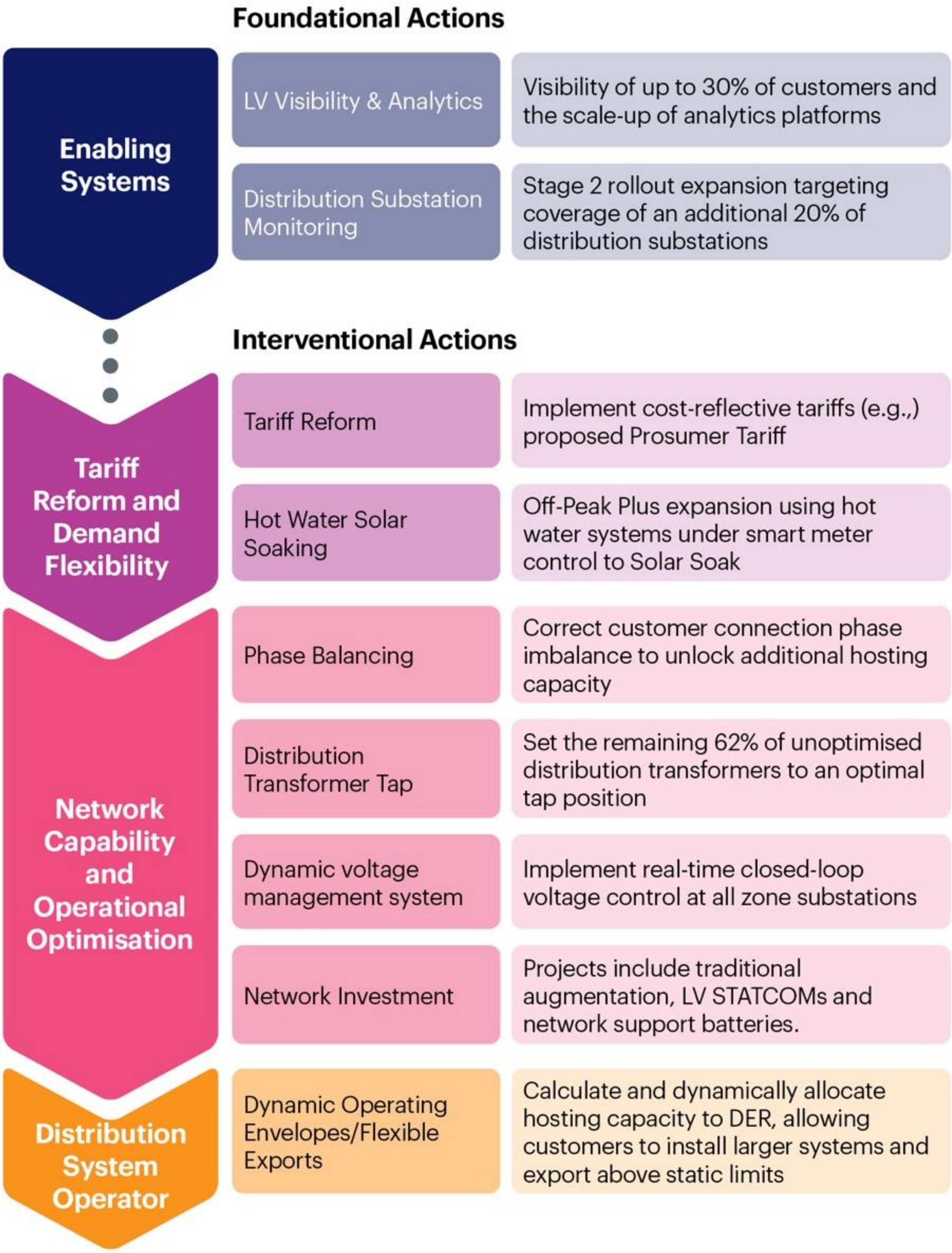
This slight reduction in maximum import demand may not be sufficient to remove the need for network augmentation expenditure, but it will influence the timing of the need for network augmentation expenditure. In particular, the tariff response will delay the need for network augmentation investment which drives down the magnitude of the future network expenditure in present value terms.

2.6.3 DER integration planning uses a hierarchy of potential strategies to reduce network expenditure requirements

During the preparation of Endeavour Energy's Regulatory Proposal for the 2024–29 period, the Future Grid and Pricing teams have met frequently and regularly to discuss tariff innovation and its relationship with CER. The frequency of these meetings has ensured that the CER integration expenditure plan aligns with the proposed tariff strategy. There is therefore a strong focus on the impact of tariffs on CER integration, as explored throughout the business cases that underpins the CER expenditure plan.

Our CER integration expenditure plan outlines these seven intervention actions, which are grouped into three key focus areas. Figure 19 presents the hierarchy of these interventions, where the relevant constraints and considerations for each action reflects only those that remain after the upstream interventions have been implemented.

Figure 19: Our CER integration expenditure action plan hierarchy

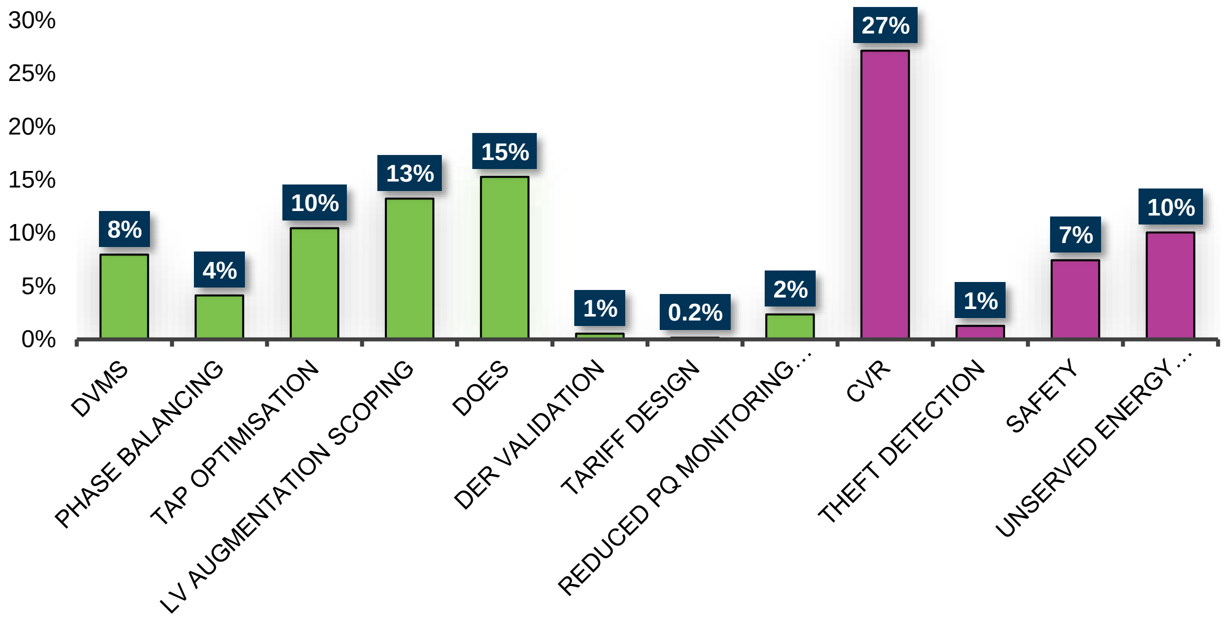


Our highest priority intervention action is ‘tariff reform and demand flexibility’, which takes precedence over network expenditure that occurs under ‘network capability and operational optimisation’ actions.

Our low voltage visibility and analytics (LVVA) foundational action achieves network benefits that are primarily driven by improvements in reliability, conservation voltage reduction (CVR), optimised network augmentation planning and the implementation of dynamic operating envelopes.

However, as shown in Figure 20, our future tariff strategy contributes to total benefits within our LVVA plan. We anticipate that $0.45 million ($FY24) of avoided network costs will be obtained through more efficient use of the network over the 2024–29 regulatory control period.

Figure 20: Benefits for low voltage visibility and analytics in the 2024-29 RCP



The current effect of tariff reform on forecast network expenditure is relatively minor but is likely to grow in the future as technological advancements facilitate more flexible load and allow for customers to change their behaviour more effectively in response to price signals.

We will continue to research and gather information to further refine and hone our tariff strategy and expenditure pathways to create value for our customers in the future. Our intended avenues of investigation in the future include:

- quantitative analysis of the price elasticity of demand and incorporating this metric in the CER integration strategy and other network planning approaches;
- visibility over the low voltage network to understand the location of assets and the ways in which customers use these assets and interact with the localised network; and
- understanding the relationship between use of the network and network expenditure that supports CER integration, acknowledging that this relationship may be different to the traditional relationship between maximum import demand, network capacity and augmentation expenditure.

In combination, this will ensure that our tariff strategy continues to support efficient network expenditure into the future, particularly as the penetration of smart meters grows and so the scope to apply more innovative tariff structures improves.

2.6.4 Continued focus on implementing technology and tariff trials

The accelerated roll-out of our 'Off-Peak Plus' incentive program forms an integral part of our CER integration strategy.

Our 'Off-Peak Plus' trial uses smart meter technology to facilitate the shift of hot water load from existing overnight controlled load tariffs to provide 'solar soaking' for excess CER generated exports in the middle of the day. We have committed to providing incentive payments to accelerate the rollout of smart meters to customers with hot water systems on controlled load tariffs. Under this accelerated roll-out, all controlled load customers will have a smart meter by 1 July 2029, rather than by 1 July 2036, as previously forecast.

Endeavour Energy will continue to use tariff trials to develop new tariffs over the course of the 2024-29 regulatory control period. Planned tariff trials include:

- Dynamic scheduled load tariffs designed to facilitate solar soaking and peak demand management using hot water and EV charging loads.

- Subject to appropriate customer connection to our network, we would like to explore options to add dynamic pricing components to our proposed HV grid connected battery tariffs.

We will strive to explore other innovative tariff options through the tariff trial mechanism in this regulatory control period.

2.7 Our role in the digital age

As discussed in section 2.5, our customers are making use of new technologies to transform their use of the network from one-way consumption to two-way energy sharing. The changing use of the network requires a change in our role and function.

We have included the provision of 'efficient and effective service in the digital age' as an emerging trend shaping our current and future operational landscape.

As our customers become increasingly sophisticated, they will turn to digital platforms to automate and optimise their network use. Open, real-time data sharing will become critical to the successful operation of our network, allowing and incentivising customers and third-parties to use their technologies to help balance the system and, through avoiding network costs, minimise their own network bill.

Evolving digital capabilities will underpin our role as the network orchestrator, and facilitate seamless, dynamic, real-time interactions between the network and the third-party platforms driving virtual power plants (VPPs) and active behind the meter participants.

Energy aggregators, such as VPPs, unlock additional value from CER for households by accessing wholesale markets, effectively transforming households into wholesale market participants that respond to price signals and deliver market services. As households become more integrated across the energy supply chain, the complexity of managing our network increases. Endeavour Energy is committed to encouraging and facilitating these types of interactions by increasing their digital capability.

We discuss the challenges associated with our changing role and the opportunities these challenges present in chapter 4.

Customer Engagement

Chapter 3

3.1 Our commitment to engagement

We have undertaken our most comprehensive and ambitious engagement program to ensure that our plans reflect the service priorities our customers have told us are in their long-term interests. We've kept downward pressure on network charges, simplified tariffs for retailers, and priced streetlighting and smart cities technologies to support councils.

Every day, Endeavour Energy engages with people and organisations who have an interest in what we do and who are, in some way, connected to our purpose. The quality of those relationships determines how well we will deliver on our vision to power communities for a brighter future.

As the Australian energy industry changes, we recognise that we need to continually improve our engagement so that our day-to-day operations and plans benefit from fresh insights and ideas.

Endeavour Energy is committed to embedding quality stakeholder engagement across our business so that it informs our actions and underpins our decisions, always placing our customers at the heart of what we do.

Importantly, it demands an "outside-in" approach to listening and acting on engagement.

Our stakeholders have told us they are interested to engage with us on many things, including: Western Sydney growth, regulatory proposals, climate change, bushfire prevention, community resilience, future grid, pricing and tariff reform and how we help vulnerable customers.

We welcome this interest and related opportunities to listen and incorporate stakeholder views so that we can design outcomes that are good for the business, good for customers and good for our communities.

We are aiming high. We are committed to listening, identifying better practice, learning from past experience, utilising international standards and building a culture of effective engagement recognised across the industry. Our goal is to embed effective business-as-usual engagement so that we strengthen a customer centric culture, reflecting the changing needs of customers and our evolving ecosystem.

3.2 Engagement Scope

Our engagement scope has been set looking outward from the regulatory framework as required by the Australian Energy Regulator.

Our Regulatory Reference Group (RRG), together with representatives of Endeavour Energy's Board and our Executive Leadership Team co-designed a map of issues for engagement, identifying their impact on the proposal and the ability of customers to influence the outcomes for each aspect of our revenue proposal on the IAP2 Spectrum of Participation.

The outcome of this process is depicted in the matrix below. If a topic sits towards the left of the matrix, customer and stakeholders are considered to have less ability to influence an outcome (for example, that item might be governed by a regulatory instrument like the rate of return).

However, if a topic sits towards the right of the matrix, customers and stakeholders have greater capacity to influence and shape outcomes. Our tariff strategy sits towards the right of the matrix, indicating a higher engagement setting (collaboration) and greater customer and stakeholder influence.

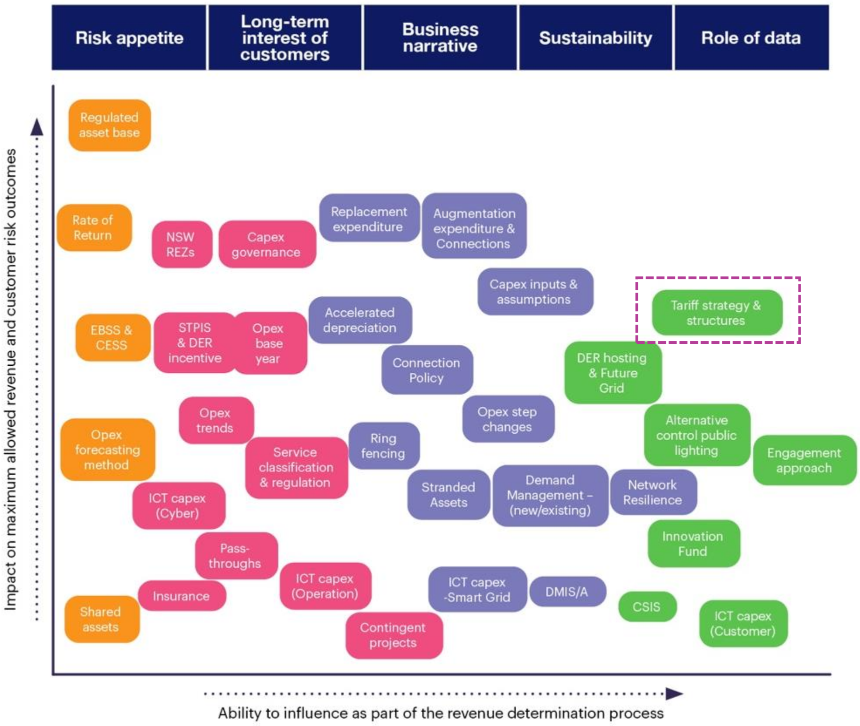
This engagement map (next page) formed a foundational reference for the entire engagement program, and includes some inform and consult elements, with many involve and collaborate opportunities – particularly for our most informed and engaged stakeholders.

Figure 21: Engagement map of 2024-29 determination matters against IAP2 spectrum

Increasing impact on the decision →

	Inform	Consult	Involve	Collaborate	Empower
Public participation goal	To provide the public with balanced and objective information to assist them in understanding the problem, alternatives, opportunities and/or solutions.	To obtain public feedback on analysis, alternatives and/or decisions.	To work directly with the public throughout the process to ensure that public concerns and aspirations are consistently understood and considered.	To partner with the public in each aspect of the decision, including the development of alternatives and the identification of the preferred solution.	To place final decision-making in the hands of the public.
Promise to the public	We will keep you informed.	We will keep you informed, listen to and acknowledge concerns and aspirations and provide feedback on how public input influenced the decision.	We will work with you to ensure that your concerns and aspirations are directly reflected in the alternatives developed and provide feedback on how public input influenced the decision.	We will look to you for advice and innovation in formulating solutions and incorporate your advice and recommendations into the decisions to the maximum extent possible.	We will implement what you decide.

Level of IAP2 Public Participation Spectrum	
Empower	To place final decision-making in the hands of customers and stakeholders.
Collaborate	To work together with our customers and stakeholders to formulate alternatives and incorporate their advice into final decisions to the maximum possible extent.
Involve	To work directly with customers and stakeholders to ensure their concerns and aspirations are directly reflected in the alternatives developed.
Consult	To obtain feedback on alternatives and draft proposals.
Inform	To provide balanced information to keep customers and stakeholders informed.



3.3 Alignment with the AER's Better Resets Handbook

The AER released its Better Resets Handbook in December 2021. It encourages electricity distribution and transmission networks to engage meaningfully with customers and stakeholders and ensure consumer preferences drive the development of regulatory proposals. The Handbook sets out the AER's expectations on consumer engagement. They cover:

- the nature of engagement
- the breadth and depth of engagement; and
- the clearly evidenced impact of this engagement.

Endeavour Energy has utilised a wide variety of engagement methods and channels to ensure the overall regulatory engagement program achieves both deep and broad engagement with a diverse cross-section of customers and stakeholders.

Some of these engagement opportunities are business-as-usual (for example, State of the Network and the ongoing Voice of Customer or Reptrak programs), but some were developed to meet specific needs of the regulatory program (for example, the RRG and the Customer Panel).

Endeavour Energy also considered ways to target specific stakeholders and customers who might be more difficult to involve in broader engagement forums. This might be because they have very specific areas of interest (e.g., large energy users or local councils) or because they are time poor, unable to share frank feedback in public settings (e.g., due to privacy or competition reasons) or just need a bespoke approach to ensure their voices are properly heard and then considered in decision making (e.g., non-English-speaking customers).

This targeted engagement typically took the form of small group meetings or workshops with smaller customer groups or stakeholder segments.

This multi-faceted engagement approach took into account feedback received following Endeavour Energy's last Regulatory Proposal and was refreshed in the Discover, Explore and Prioritise phases of this program, where stakeholders were asked for their engagement preferences.

This mixed method approach ensured a comprehensive understanding of a wide range of customer and stakeholder views and preferences.

Figure 22: Summary of breadth and depth of Endeavour Energy's engagement methods

Deep engagement methods	Broad engagement methods	Targeted engagement methods
• Customer panel • RRG engagement, including a series of additional small workshops ('mini–Deep Dives) with subject matter experts on key topics chosen by the RRG • Peak Customer and Stakeholder Committee (PCSC) engagement • Stakeholder Deep Dives • Future grid workshops	• Residential and SME customer quantitative survey • RepTrak surveys with end customers and stakeholders • Exploratory focus groups with end residential and SME customers • State of the Network forum with a broad range of stakeholders • Joint stakeholder workshops with other DNSP's including on Resilience • A 'Have Your Say' section on the Endeavour Energy website • LinkedIn and Facebook posts	• Culturally and linguistically diverse (CALD) in-language engagement • High-energy users workshop • 'Dinners with Endeavour' in-language engagement • Local council workshops • Meetings with commercial and industrial energy users • Meetings with retailers, market aggregators, large storage providers and other new market entrants

3.4 Engagement program

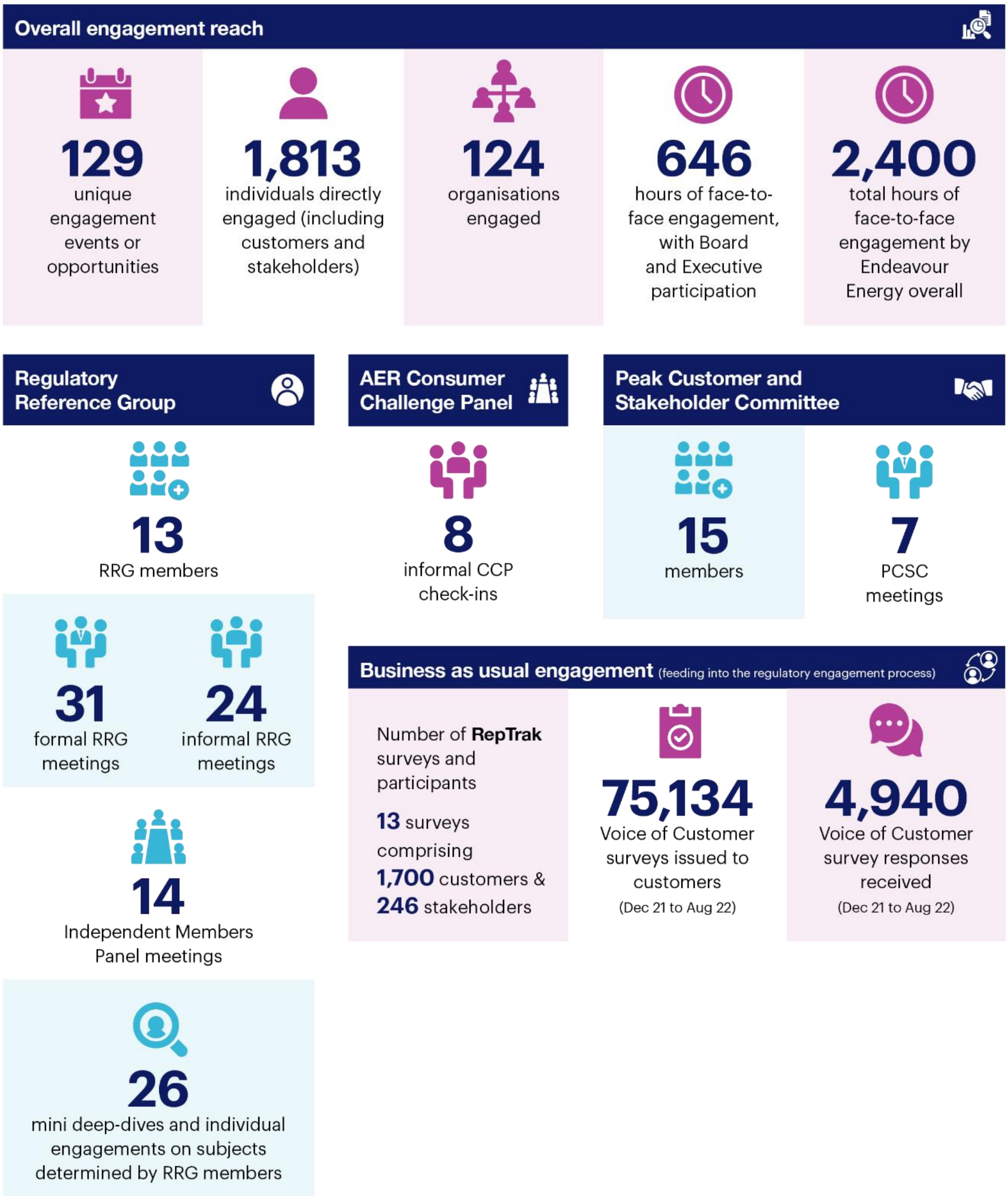
The engagement program initially compromised four key phases, each with distinct deliverables. In response to recommendations of the RRG Independent Members Panel, a fifth phase, the ‘Confirm Phase’ has been added to our engagement plan to cover the period after the submission of our Regulatory Proposal to the AER, and the ‘Refine Phase’ has been augmented to sense check potentially changing customer preferences. The program is summarised as follows:

Figure 23: Endeavour Energy’s 2024-29 engagement program summary

Preparation	Phase 1 **Discover**	Phase 2 **Explore**	Phase 3 **Prioritise**	Phase 4 **Refine**	Phase 5 **Confirm**
Oct 2020 – Mar 2021	Apr 2021 – Sept 2021	Oct 2021 – Apr 2022	May 2022 – Oct 2022	Nov 2022 – Jan 2023	Feb 2023 – Jul 2023
A period of forward-planning to prepare Endeavour Energy for the launch of the regulatory cycle	A research period to better understand customer and stakeholder needs and preferences to help shape our engagement approach	A period of deeper exploration of key issues to help inform the development of our Preliminary Proposal	Broad and deep engagement on our Preliminary Proposal, identifying aspects of greatest importance to customers	Developing and refining our Final Proposal using insights from the previous phase	Confirming our customers’ priorities in the context of a changing economic environment
• Benchmarking previous engagement with best practice • Engagement partner appointed • PCSC membership enhanced	• Establishment of RRG, FGRG and ReRG and determine the Terms of Reference • Board/Executive/ customer co-design workshop • RRG engagement planning • Joint DNSP engagement (emerging services) • Future Grid workshop • Co-designed exploratory research straw man • Board check-in • PCSC • Exploratory research (residential) • Exploratory research – SME (Dinners with Endeavour) • Exploratory research (CALD) • Ongoing engagement with AER	• RRG and AER Investment Value Framework • BAU State of the Network Forum (Illawarra and South Coast) • BAU State of the Network Forum (Greater Western Sydney) • High-energy users’ workshop • Future Grid workshops • RRG • PCSC x 2 • Joint DNSP engagement (tariffs) • Ongoing RRG mini Deep Dives • Board check-in • Commence engagement of AER’s CCP • Ongoing engagement with AER • One-on-one briefings with stakeholders • RepTrak benchmarking study	• Local Council Workshop (Illawarra and South Coast) • Local Council Workshop – Western Sydney) • Customer Panel Wave 1 • Customer Panel Wave 2 • Deep Dive 1 • Deep Dive 2 • One-on-one briefings with stakeholders • Quantitative survey • RRG webinars x 3 • PCSC x 3 • Ongoing RRG mini Deep Dives • In-language direct engagement with CALD communities • Customer Panel Wave 3 • Ongoing engagement with AER	• Stakeholder check-ins • Individual retailer engagements • Local council workshop (street lighting tariffs check-in) • RRG bi monthly meetings • RepTrak benchmarking study	• Customer Panel check-in • Stakeholder check-in • RRG bimonthly meetings • AER public hearing
	• Engagement Plan • Exploratory Customer Research Report	• Preliminary Proposal • Business Narrative	• Draft Proposal • Engagement Summary Report	• Final Proposal • Final Proposal Customer Overview	

Our Engagement Summary Report provides a comprehensive overview of the design and execution of our engagement plan, which was designed to be iterative and characterised by constant and incremental changes to our positions based on numerous ‘pillars of evidence’. A ‘by the numbers’ summary of our program is provided below as an overview:

Figure 24: 'By the numbers' summary of Endeavour Energy's 2024-29 engagement program



Online and digital engagement

16 regulatory reset stories posted to LinkedIn with a reach of

40,075

6 regulatory reset stories posted to Facebook with a reach of

41,743

Your Say engagement
(private RRG page)
97 newsfeed articles,
179 documents and
565 downloads

Newsletters
5 sent
913 opens
68% average open rate

Your Say engagement (public engagement portal)
1,871 'aware visitors'
1,362 'informed visitors'
(engaged with material on the site)
3,150 downloads
1,066 downloads of the Preliminary Proposal
369 downloads of Draft Proposal
202 downloads of Engagement Summary Report

Customer Panel

89 Customer Panel members

1,513 hours of Customer Panel engagement

10,633 unique responses from Customer Panel members

CALD and First Nations people engagement

20 different language groups represented

230 CALD participants

52 First Nations people participants

Core engagement documents and co-designed revisions

6 versions of the Engagement Plan

5 versions of the Business Narrative

8 versions of the RRG Terms of Reference

A highlight of our process was the Prioritise Phase of engagement, which involved the most extensive and broad reaching component of our program. It followed the release of our Preliminary Proposal in April 2022, and sought to reveal what customers valued most, acknowledging constraints on investment were necessary to balance our customers' vision for their future service with affordability that delivers value. We provide a brief summary of some of the key aspects of our Prioritise Phase of engagement below.

3.5 Customer Panel

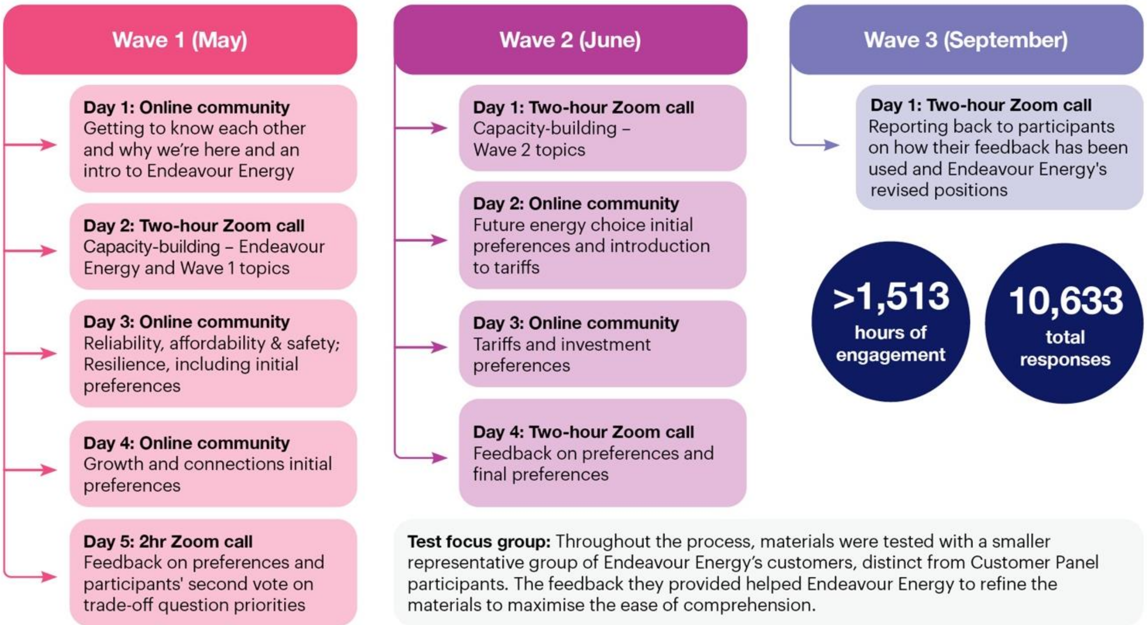
The Customer Panel was a key element of our engagement approach. Its purpose was to deeply engage with a broad and representative cross-section of residential and small business customers through an extended deliberative process to inform Endeavour Energy's Draft Proposal.

The Panel comprised 89 participants who were provided extensive background information and undertook many different capacity-building activities in an online community to deliberate on the following key questions that were co-designed with the RRG Independent Members Panel:

1. How should Endeavour Energy best meet customer expectations for a safe, reliable and affordable electricity supply?
2. Should Endeavour Energy take a more proactive or responsive approach to maintaining network services in the face of increasing major weather events (storm, bushfire, flood, urban heat, etc)?
3. How should Endeavour Energy time the delivery of the electricity infrastructure required for the economic development of Greater Western Sydney and other areas?
4. Should new customers be required to pay “upfront” for the infrastructure required to service new development, or should the costs for this infrastructure be recovered over time from all customers through existing charges?
5. How do we modernise the network to meet emerging and future customer service expectations as technology and markets evolve?
6. Should tariffs reflect the different demands customers place on the network?
7. Should solar exports tariffs be introduced by Endeavour Energy to reflect the different demands customers place on the network?
8. Does Endeavour Energy’s proposal reflect customers’ priorities, preferred outcomes and long-term interests by providing a reliable, affordable and safe distribution network?

These questions were tested multiple times both with and without indicative bill and service outcomes, both individually and in combination over multiple waves. This process is depicted below:

Figure 25: Summary of Customer Panel process and engagement



3.6 Deep Dives

In order to explore any divergence between the views of customers and stakeholders, the Customer Panel’s preferences from Waves 1 and 2 were shared with a broad group of stakeholders in a series of full day Deep Dives in July and August 2022.

The Deep Dives involved more than 100 well-informed customer advocates who represented a diverse set of views across 13 different customer segments, from Accredited Service Providers (ASPs) to developers, sustainability and technology businesses to advocates of vulnerable customers. Ahead of each session, participants were urged to read the Preliminary Proposal to understand Endeavour Energy’s emerging views. Participants were also sent a range of questions to consider, ensuring they arrived ready to provide meaningful contributions.

Stakeholders attending the Deep Dives were asked for their preferences on exactly the same questions put to our Customer Panel – and asked to explore the alignment or misalignment of their views with our customers.

This process allowed for sophisticated and informed discussion, which included robust challenge of Endeavour Energy's positions and deep examination of how the competing preferences of customers should be balanced. It put our customers' views at the centre of our 'Prioritise Phase' of engagement.

These stakeholder views were subsequently shared with the Customer Panel to provide them with oversight of different perspectives for their final deliberations in Wave 3.

3.7 Refine Phase (Phase 4)

We have received positive feedback on our Draft Proposal, which responds to the outcomes of the Prioritise Phase from the Customer Panel and the Independent Members Panel of the RRG. We continued to engage with key parties to refine our proposal prior to submission of this Proposal to the AER. This included:

- **Sense check survey & individual submissions:** Following the publication of the Draft Proposal in October 2022, we sought further feedback from customers and stakeholders regarding the Draft Proposal to refine our plans for lodgement with the AER. In addition to seeking individual submissions, a 'sense check' survey was issued in November 2022 to more than 350 customers and stakeholders and published on our Your Say Engagement Platform and social media channels to capture a broad range of feedback regarding our responses to the key themes of our engagement. The November survey was also designed to capture any recent shifts in preferences, especially with regards to affordability, in the changing economic environment. This survey was developed in consultation with the Regulatory Reference Group and complements feedback from stakeholders gathered during the development of the Draft Proposal. We received responses from Council of the Aging NSW, Energy Australia as well as a Council and customer. Across the individual topic areas in the Draft Proposal covered by the survey, 57% of responses rated Endeavour Energy's approach as 'somewhat acceptable', 18% 'very acceptable', 21% 'neither acceptable nor unacceptable' and 4% 'somewhat unacceptable'.

  Endeavour Energy also received three individual submissions. These included a combined submission from Business NSW and Business Western Sydney that commended Endeavour Energy's engagement for its engagement and endorsed the Draft Proposal; a submission from the Caravan, Camping & Touring Industry & Manufactured Housing Industry Association of NSW that encouraged further discussion about fair and equitable approaches to embedded network tariffs and their potential impacts on holiday parks and residential land lease communities; and a submission from a residential customer seeking information about microgrids and offering advice regarding the accessibility of our regulatory documentation. Refer to attachment 5.18 of our Regulatory Proposal for more detail.

- **Ongoing engagement with Retailers and Market Small Generator Aggregators (SGA):** In addition to the ongoing engagement with retailers through our Retailer Reference Group, Endeavour Energy held roadshows with six retailers (large and small) in the Refine Phase of engagement. Retailers supported the direction of the tariff strategy, which is centred on an accelerated uptake of cost reflective tariffs and increased simplicity. Retailers had differing views on the value of demand-based tariffs and on what constitutes increased simplicity for customers and increased simplicity for retailers. Retailers can continue to respond to options regarding the implementation of cost reflective tariffs for Endeavour Energy customers including the adoption of a transitional tariff and offering demand tariffs as an alternative to time of use tariffs.

  Given the increasing importance of the emerging energy markets, Endeavour Energy also actively sought feedback from emerging market participants on innovation, non-network market providers, and how tariffs can support a fair and efficient energy transition. This included workshops with several Market Small Generator Aggregators (SGA) with energy storage, aggregation or hybrid facilities. SGA's supported the direction of Endeavour Energy's proposal in regards to new and flexible market considerations, tariff reform, and how to best facilitate the increasing uptake of Customer Energy Resources. They highlighted the need for continual engagement and support to ensure customers long term interests from all parties in the energy supply chain.

- **Tariff engagement and pioneering Persona work:** Given the support for tariff reform from the Customer Panel weakened over the 5 months of engagement, Endeavour Energy sought to develop a greater understanding of the non-technological barriers to the uptake of cost-reflective tariffs by customers, and the narratives, messages and collateral that might lead to increased customer comfort with a move to mandated cost-reflective tariffs. Research was commissioned and completed in January 2023 to target our ongoing engagement in order to support our approach to introducing mandated cost-reflective tariffs that meet the needs of customers. This included pioneering persona work, transitional arrangements, simple educational messaging and key information, engagement and resources to best support customers adapt and respond to pricing signals. Refer to attachment 5.19 of our Regulatory Proposal.
- **Ongoing local council engagement:** Endeavour Energy routinely engages with local councils and Regional Organisations of Councils. Following our Prioritise Phase local council workshops and a webinar regarding public lighting tariffs, three of the 22 councils we engaged responded to our offer of one-on-one engagements in the Refine Phase on the implications of the new public lighting tariffs for their communities. The public lighting tariffs have been well received by councils and the Independent Members Panel of the RRG.
- **Independent review of our engagement:** We also commissioned an independent review of our customer engagement program supporting the development of this Proposal. This review included twenty-five interviews with key stakeholders and identified differences of opinion were at the margins, with all stakeholders agreeing that the codesign engagement had been successful and that Endeavour Energy had met the AER expectations as defined in the AER's Better Resets Handbook. Further, this review identified that the customer engagement was genuine, authentic, sincere, active, and positive. That there were innovative features of the engagement, in particular the "Dinner with Endeavour Energy" events that were very successful in engaging customers of culturally and linguistically diverse backgrounds. The review concluded that the involvement of Board members, the CEO, executives and senior staff in the engagement sessions had a significant positive impact, with customers reporting that they felt listened to and respected. Finally, the report reflected that while there was no single major change in the proposal, instead it was a longitudinal series of waves of changes, with a pattern of inform, listen, adapt, re-present, listen, adapt. For further detailed refer to attachment 5.17 of our Regulatory Proposal.

3.8 Customer Panel (Wave 4)

Our January 2023 TSS submission included the proposal to transition customers onto our Seasonal TOU Energy tariff via a 24-month transition period under the proposed assignment policy. This was proposed to mitigate any adverse impacts on customers and allow more time for customers to adapt to cost-reflective pricing options.

As part of our ongoing engagement with customers, stakeholders and retailers, and following our tariff knowledge review earlier in the year, we chose to re-test customer appetite around our tariff transition plans[20, 21] .

The following question was taken to our Customer Panel in June 2023:

[20] In their March 2023 report, (report 3), the RRG Independent Members Panel outline their preference that customers should be shifted to cost-reflective tariffs as quickly as possible. They argue that a transitional tariff creates confusion for customers and additional administrative costs as tariffs are changed multiple times. They are concerned this cost will be passed through to customers. They also note that a 12-month transition creates alignment in process across NSW DNSP's (page 13).

[21] In their May 2023 submission, Red Energy and Lumo Energy argue that the 24-month transition is unnecessary as the proposed default time of use tariff can be comprehended customers and responded to with relative ease (page 4).

Thinking about the staged transition to time-of-use tariffs, which of the following would you prefer? Why do you say that?

A. A 12-month transition comprising educational support before the transition to full time-of-use tariffs.

B. A 24-month transition to shift to time-of-use tariffs which includes:

   i. a 12-month period of educational support and no change in tariff arrangements AND

   ii. an additional 12-month period with ongoing educational support as well as a 'transitional' tariff offered to retailers which is 50% cost reflective before the full time-of-use tariff commences.

Over two thirds of Customer Panel participants preferred retailers are offered a 12-month transition to time-of-use network tariffs, largely as they wanted to access these tariffs to save money as soon as possible by changing the time of day they consume electricity.

Two thirds of participants said they'd prefer a 12-month transition due to:

- A desire to save money sooner by changing when they consume electricity, particularly in light of current cost-of-living concerns, with some asking if could happen in less than 12 months;
- A belief that 12 months would be enough time for customers to prepare for the transition; and
- A view that a 24-month transition will be more confusing for customers and may mean retailers will "drag their feet" in making the transition.

The third of participants who preferred a 24-month transition cited:

- The need for more time for customers to prepare to benefit from time-of-use network tariffs, including by installing smart meters, solar panels and batteries. Some participants with solar panels noted they would need more time to invest in batteries as time-of-use network tariffs would reduce the financial benefits of solar panels.; and
- Concern that some customer types (e.g. elderly, financially vulnerable) might benefit from more time for education to mitigate negative impacts.

In response to this feedback, we are now proposing to shorten the transition period to a12-month period, whilst providing appropriate support and education for our customers.

3.9 What we heard from our customers and how we will respond

Our key tariff engagement findings and responses are summarised below:

Table 2: Engagement findings and response

What we heard	How we have responded
• In-principle, customers are supportive of cost-reflective tariffs. • The majority of customers preferred an opt-in approach to both cost-reflective and solar export tariffs as they prioritised choice and were concerned about the ability of customers to change their behaviour in response to different tariffs. • Most customers felt that a transition period and education would be important.	• We are working with retailers to transition customers with smart meters to cost reflective tariffs, and we will support this change by conducting the transition over a 12-month period to help customers understand their energy usage and adjust their behaviour to take advantage of cost reflective tariffs; by working with retailers to understand what educational support customers need to make a smooth transition to cost reflective tariffs.

What we heard	How we have responded
• Other stakeholders were more supportive of mandating cost-reflective, solar export and other future new tariffs quicker.	• We will work with retailers to introduce a solar export and reward tariff on an opt-in basis from 1 July 2024. However, from 1 July 2025, we will place all new and upgrading solar customers on the tariff as the default, which they can chose to opt out of.

3.10 Key priorities from customers

In the future, customers have also identified emerging priorities:

- widespread interest from customers in hearing about ways they can save money by changing behaviour;
- more choice and control – there is an increasing expectation that customers will have access to grid-connected solar PV and other new technologies to save money and improve their sustainability; and
- new opportunities to save money – Endeavour Energy can support improving energy affordability by facilitating customer access to new technology, improved visibility and management of their energy usage and incentive pricing.

Key opportunities and challenges

Chapter 4

4.1 Slow uptake of cost reflective tariffs

In this section, we summarise the issues we have experienced in transitioning our low voltage customers to more cost-reflective tariffs. Details of our assignment policy are contained in section 5.3.1.

In 2019–24, our assignment policy for low voltage customers included an opt-out clause that allowed retailers to control the speed of the cost-reflective tariff transition. In addition, this transition has been slowed by the proportion of basic meters still in use across the network, the rollout of which is also controlled by retailers.

The table below demonstrates the relatively slow roll-out of smart meters and cost reflective tariff uptake since the commencement of the 2019-24 regulatory control period. In light of slow uptake of these tariffs, we would like to increase the pace of transition in the 2024-29 regulatory control period.

Table 3: Proportion of customers with a smart meter and cost reflective tariff

Type	Technology	June 2019	June 2022
Residential	Customers with a smart meter	14%	31%
	Smart metered customers on a cost reflective tariff	0%	22%
SME	Customers with a smart meter	11%	25%
	Smart metered customers on a cost reflective tariff	29%	34%

We included the opt-out provision for cost reflective tariffs in our 2019–24 TSS to manage bill impacts, even though we agreed with the AER that our cost-reflective tariffs would be priced favourably, in comparison to other tariffs.[22]

Given that retailers have had the opportunity to prepare since 2019, we believe there is opportunity to be more aggressive in our re-assignment policy in the 2024–29 regulatory control period to increase the pace of transition to cost-reflective tariffs. In particular, we will reassess the need for a retailer opt-out clause for low voltage customers.

This follows recent encouragement from the AER to the Victorian distributors to reassign all customers to new cost reflective tariffs,[23] made possible by the rollout of advanced metering infrastructure in Victoria.

To minimise customer bill impacts during this transition, we will maintain the attractiveness of our cost reflective tariffs relative to the alternatives. The benefit of our cost-reflective tariff is the highly targeted on-peak period, which is one of the shortest peak charging windows in the NEM and provides our customers significant opportunity to change their behaviour and reduce their bill.

However, customers with low usage or reduced ability to shift their load from the on-peak period may be adversely affected by cost-reflective tariffs. These customers must be protected from undue bill shocks under any change to our assignment policy.

[22] Endeavour Energy, *Tariff Structure Statement | 1 July 2019 – 30 June 2024*, January 2019, p 29.

[23] AER, *AusNet Services, CitiPower, Jemena, Powercor and United Energy 2021-26 | Attachment 19 | Draft decision*, September 2020, pp 50-52.

4.2 Implementing two-way tariffs

Our CER integration expenditure program has identified $76 million of expenditure in the 2024–29 regulatory control period that is related to the increase in exports on our low voltage network. To maintain the cost-reflectivity of our network tariffs, we need to signal to our customers how their use of the network may contribute to or help avoid these costs.

By signalling these future network costs, our customers can indicate where and how they value investment in augmented network capacity, i.e., the circumstances in which network investment is the least cost solution.

There are two principal periods in which a change in the use of our network may have a non-negligible impact on our costs, i.e., peak demand (in the evening) and peak export (in the middle of the day) events.

We present these periods and their interaction with a customer's use of network in Table 4. Currently, our network tariff strategy only sends an import signal during peak demand events.

Table 4: Relationship between customer behaviour and network costs

Customer type	Driver of network cost	Behaviour that can avoid network costs
Peak demand events	*High imports*	*Lower imports and/or higher exports*
Peak export events	*Low imports and high exports*	*Higher imports and/or lower exports*

Economic efficiency is promoted by signalling to customers how each of these behaviours in the right-hand column above can lower our network costs. In practice, this necessitates price signals for both imports and exports and positive incentives such as rewards, for example, rebates or negative prices.

These signals are an integral part of our two-way pricing strategy that can improve the utilisation of the network.

We are presented with an opportunity to use two-way price and reward signals to encourage customer-led solutions that avoid the need for costly future network expansion. Avoiding these network costs will reduce our customers' electricity bills.

If follows that we can use our two-way pricing strategy to encourage customers to:

- shift discretionary load into peak export events, i.e., to provide a 'solar soak', which may include the installation of behind the meter batteries; and
- minimise the amount of excess solar generation that is exported back onto the network during export peak periods, e.g., orienting solar panels to the west.

This behaviour will effectively flatten the daily load profile of our customers and increase utilisation on our network, i.e., make better use of existing network capacity.

In addition, cost-reflective two-way pricing can help unlock some currently untapped benefits of energy sharing initiatives that help alleviate network constraints e.g., community batteries.

We provide more detail for our approach to two-way tariffs in section 5.3.5.

4.3 Incentivising innovative network uses and services

Designing tariffs that do not favour one technology type over another is an important characteristic of our tariff strategy. That said, are mindful of minimising connection risk or uncertainty for some emerging technology and connection types, such as:

- large scale grid-connected batteries; and
- electric vehicles, both residential and dedicated fast charging stations.

This regulatory control period is the ideal time to implement specifically designed tariffs that can encourage these types of connections onto the network. While these technology types are an important aspect of the energy transition, there may be some commercial or implementation issues restricting their widespread application.

There is opportunity to design tariffs that better align with the characteristics of these technology types and can provide more favourable connection conditions while still sending efficient price signals.

Large scale grid-connected batteries and dedicated EV fast charging stations may be eligible for an individually calculated, site specific tariff and so a revised methodology for these types of tariffs may help incentivise more connections to our network.

4.3.1 Grid-connected batteries

We have found it difficult to incentivise large scale grid-connected batteries to connect to our network. This difficulty stems from a lack of agreement on the contribution these customers should make to the recovery of the efficient cost of our existing network, in comparison to other customers.

The challenge before us is to incentivise the connection of large-scale batteries, while ensuring that they make an equitable contribution to our network costs, bearing in mind that they may ultimately operate to provide services other than network support.

Large scale battery proponents often assert that our existing network tariffs are too costly, however due to their large size, a single connection has the potential to impose significant network costs by operating in a manner that does not align with our interests.

We design our tariffs as a means of protecting the network from these potentially costly events, however in response, battery proponents have suggested that our large-scale battery tariffs were too costly or were too restrictive.

The inherent uncertainty about the potential operation of a large-scale battery and the costs and benefits that may be imposed on the network makes it difficult to agree with the proponents on the appropriate structure and magnitude of the tariffs.

We are presented with an opportunity to work with battery proponents to find the right balance between certainty and flexibility. Our starting point is to ensure fair and equitable residual cost recovery and to send LRMC-based price signals and rewards for exports and imports, thereby ensuring that batteries have all the information required to operate efficiently.

4.3.2 Dedicated EV charging stations

As private and commercial vehicles are progressively electrified, the need for public charging stations will grow.

The relatively low uptake of EV at present means that the utilisation of EV charging stations is too low to support them making a contribution to our residual costs commensurate with that made by other customers with similar demand characteristics.

However, these dedicated charging stations are a key enabler of the transition towards widespread EV adoption by alleviating ‘range anxiety’ i.e., where EV owners are concerned of depleting their battery on longer drives due to a lack of charging points.

As with our approach to large scale batteries, we are in a unique position to rethink our large-scale commercial tariffs to better accommodate connections with highly uncertain load during their initial uptake of EVs.

The challenge before us is therefore to strike an appropriate balance between supporting these customers during the initial uptake of EVs, promoting economic efficiency and promoting fairness for our other customers.

Our tariff strategy will therefore consider ways in which we can offer more favourable tariffs for connections with low utilisation, while also remaining fair for other connection types.

4.3.3 Residential EV charging

As discussed in section 2.5.3, private EV charging is expected to drive a significant increase in peak demand. We are looking to develop a cost reflective tariff that helps avoid this potential increase in system peak demand.

Residential EV charging load is unique in that it may be stable and predictable over time, while also being reasonably flexible. Despite this flexibility, we must ensure that our customers can use their EV when they need to, particularly for emergencies.

The challenge with designing a residential tariff is to encourage the load to occur at times when it benefits the network the most, i.e., in the solar soak period, and when network costs are minimised, i.e., overnight.

However, a single EV can represent a significant portion of a typical residential load. High forecast penetration and unintended consequences of our tariff design today could have substantial influence in the future. By way of example, EV load may be incentivised to charge slower and at the conclusion of the evening peak, when usage charges are lower because there is currently excess capacity on our network. However, if EVs all fast-charge at the same time – e.g., at the end of the evening peak – it could cause an entirely new, localised peak to occur overnight.

The relevant trade-off for residential EV charging is to provide our customers with sufficient flexibility to charge at times that suit them, with contingencies for an emergency, while also ensuring some degree of certainty from the network that EV load can be controlled, so as to not cause new network constraints.

In addition to tariff design, our assignment policy must be updated to ensure all customers with an interval meter be assigned to a cost reflective tariff during the 2024-29 regulatory control period.

4.4 Embedded networks

As discussed in section 2.2, our network is growing at a rapid rate driven in part by significant Greenfield developments across the network. We anticipate that a proportion of these developments will become embedded networks.

We want embedded networks to be created because they are efficient and benefit the customers within them, not because those customers benefit – at the expense of other customers – by making a much lower contribution to recovering the cost of our existing network.

This inappropriately low contribution arises because, at present, embedded networks are treated as a single customer that pays a single, low fixed charge. However, absent that embedded network, each individual customer in the embedded network would contribute to recovering the cost of our existing network through the payment of a fixed charge.

Just like all our other customers, customers within an embedded network benefit significantly from the reliability provided by our existing network. They should therefore make a fair contribution to the cost of our existing network.

The current, inequitable outcome is not consistent with the Rules.[24]

There are a range of network benefits – and so network tariff savings – that can be obtained by an embedded network, in comparison to directly connected customers. Some of these savings reflect the lower costs imposed on the network by an embedded network while others result from taking advantage of our current tariff design, as presented in Table 5.

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[24] See the Rules, clauses 6.18.3(d) and 6.18.4(2).

Table 5: Non-network cost savings of embedded networks

Potential network benefits from embedded networks	
Diversified demand	*The coincident maximum demand of the aggregate embedded network is lower than the sum of maximum demand for each connection. This results in a lower demand-based charge for the embedded network.*
Behind-the-meter generation	*Load can be sourced locally from any excess generation within the embedded network, hence avoiding costs on the rest of the network.*
Competition efficiency	*Connections within an embedded network can invest in CER to provide benefits in the embedded network.*
Network opex savings	*The formation of an embedded network may lead to incremental vegetation management, maintenance and emergency response opex savings for the network.*
Savings that do not reflect the costs avoided by embedded networks	
Residual cost recovery avoidance	*Customers in an embedded network contribute less to residual cost recovery than similar customers that are not within an embedded network.*

Any proposed solution to the issues presented by embedded networks should address the unfair savings of embedded networks while also recognising the network benefits associated with embedded networks. This should occur without infringing on any of the additional legitimate benefits an embedded network can derive from a response to the price signal.

As the prevalence of embedded networks continues to increase over time, this inequitable allocation of residual costs will result in relatively higher costs for those customers that are not connected within an embedded network. In this sense, our existing treatment of embedded networks is creating systematic inequities between customers within an embedded network, and similar customers that are not within an embedded network.

It follows that there is a need to consider whether embedded networks are charged differently from other network connections, to ensure the consistent treatment of similar customers, consistent with the requirements of the Rules.[25]

[25] The Rules, Clause 6.18.4(2).

Our Network Tariff Reforms

Chapter 5

This section presents our proposed network tariffs for the 2024-29 regulatory control period. The purpose and principles that underpin our network tariff strategy have been designed and developed with our customers to ensure that their needs are met.

A detailed description of our proposed tariffs is included in Appendix 3.

5.1 Pricing objectives

The overarching purpose of our tariff strategy is to make energy more affordable by providing customers with the information they need to make informed, efficient decisions on their use of the network and investment in new technologies such as solar, batteries and electric vehicles.

Enabling customers to make efficient decisions on their network use and investments in technologies like solar PV, batteries and electric vehicles also help us to identify when a network investment is the lowest cost solution, and when customers are willing to pay for the cost of that investment.

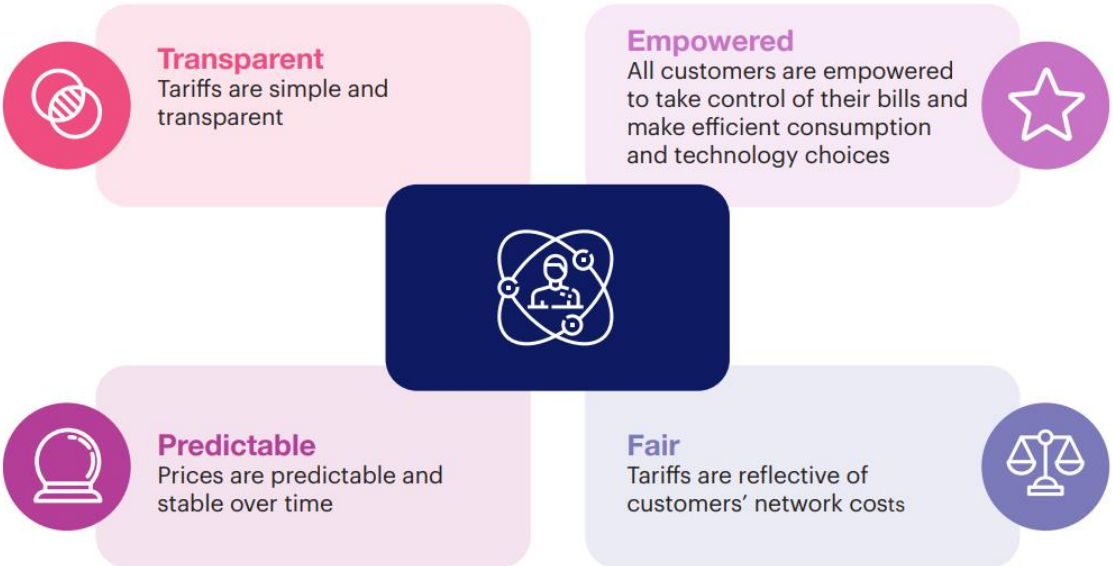
The pace of this reform is impacted by:

- Our customers' preferences;
- The impacts on their network bill; and
- the roll out of smart meters, which enable us to provide more efficient price signals.

This means our tariff reform strategies evolve as stakeholders' views evolve and new technologies and service models emerge. We will also continue to implement tariff trials to test innovative new tariffs that might better meet customers' needs.

We engaged with our RRG in developing our guiding principles, which are summarised in Figure 26. Carefully considering the needs of all our customers, large and small, is central to our strategy. Our objective and principles are consistent with the Network Pricing Objective and the Pricing Principles set out in the Rules.

Figure 26: Endeavour Energy's pricing objective



5.2 Tariff classes

We have retained the same network tariff classes used in our 2019-24 regulatory control period and revised the descriptions of these tariff classes to incorporate export service considerations.

Our tariff classes are set on the basis of:[26]

- the nature of the customers' connection to the network, i.e., whether they are high or low voltage customers or whether they are metered or unmetered; and
- the nature and extent of customers' network usage, i.e., above or below a specified level of consumption or export per annum.

A summary of our network tariff classes for Standard Control Service (SCS) is set out in Table 6.

Table 6: Endeavour Energy network tariff classes

Customer type	Tariff class	Connection characteristics
Residential and small to medium enterprise businesses	Small Low Voltage	LV Connection (230/400 V) Total electricity consumption or exports, per financial year, is less than 160MWh
Larger commercial and light industrial	Large Low Voltage	LV Connection (230/400 V) Total electricity consumption or exports, per financial year, is greater than 160MWh
Industrial	High Voltage Demand	HV Connection (12.7 kV SWER, 11 or 22 kV)
Industrial	Sub-transmission Demand	ST Connection (33, 66 or 132 kV)
Distributors	Inter-Distributor Transfer Demand	Distributor Transfer
Unmetered	Unmetered Supply	Unmetered

Our existing tariff classes are economically efficient[27] because customers within each of our existing tariff classes place similar demands on our network. Grouping customers into these network tariff classes therefore means that customers with similar characteristics and similar demands on our network face similar price signals.[28] Our existing tariff classes also avoid unnecessary transaction costs.[29]

Our tariff class definitions also ensure customers with micro-generation facilities are allocated to the same tariff class as those customers without such facilities, but with a similar load profile.[30]

Endeavour Energy also provides customer-specific or customer-requested services – referred to as Alternative Control Service (ACS). The full cost of ACS is recovered from the relevant customer. The AER determines the price, or the unit rates used in quoting for an ACS.

[26] The Rules, clause 6.18.4(a)(1).

[27] The Rules, clause 6.18.3(d)(1).

[28] The Rules, clause 6.18.4(a)(2).

[29] The Rules, clause 6.18.3(d)(2).

[30] The Rules, clause 6.18.4(a)(3).

We propose the following categories of direct control services as ACS:

- ancillary network services;
- public lighting; and
- security lights (Nightwatch).

Endeavour Energy proposes that customers that use these categories of service form our ACS tariff classes. A summary of our ACS tariff classes is set out in Table 7.

Table 7: Endeavour Energy ACS tariff classes

Customer type	Tariff class	Service characteristics
Retailers and ASPs on behalf of customers	Ancillary Network Services	Would include authorisations, inspections, permits, site establishment, connections/disconnections and conveyancing information. Service is initiated only at customer request.
Public space illuminators (generally local councils)	Public Lighting	Provision of public lighting infrastructure. Maintenance of public lighting infrastructure. Retirement of public lighting infrastructure.
Customer requested flood lighting services	Security Lights (Nightwatch)	Provision of lighting infrastructure. Maintenance of lighting infrastructure. Supply of energy for lighting service.

We consider our proposed ACS tariff classes to be economically efficient.[31] This is because customers within each of our existing tariff classes place similar demands on our resources – by grouping our customers into these network tariff classes we believe that customers with similar service requirements will pay consistent prices as determined by the AER's form of control.

5.2.1 Reclassifying Metering as a SCS

As discussed in section 4.3 of our Revised Proposal, there has been a material change in circumstances since the lodgement of our January 2023 Proposal with respect to Type 5 & 6 (Legacy) Metering Services. The AEMC's final metering framework review sets out a number of reforms that will be implemented via a rule change process over the coming months. These reforms aim to establish a process for accelerating the retirement of existing legacy meters and framework for the sharing of basic power quality data.

We support these reforms and consider the contestable metering framework has failed to transition customers to smart metering in a timely manner or unlock the benefits associated with it. However, the reforms also bring into question whether the existing regulatory approach for legacy metering remains suitable. We do not consider an ACS classification will best promote the long-term interests of customers under an accelerated transition.

As the legacy metering customer base progresses towards a small number of customers a significant equity issue arises. This smaller customer base could face exponentially increasing prices to recover the outstanding metering asset base and the ongoing operating costs which do not reduce 1:1 with reductions in the customer base.

[31] The Rules, clause 6.18.3(d)(1).

In addition, the AEMC notes that vulnerable customers face higher risks of being excluded from the roll-out because[32]:

> *……they are more likely to be in positions where decisions making regarding remediation is out of their control and face higher financial hurdles for undertaking remediation. Vulnerable energy customers can overlap with the more socio-economically disadvantaged parts of the community. Customers who don't own their own homes or live in social or public housing are more likely to fall into the vulnerable energy customers category. In many cases, such customers may not have the required authority to make decisions regarding undertaking remediation. Electrical installations generally form part of the infrastructure that the building owner or operator is required to provide and maintain. This would leave vulnerable customers in a position where they are less able to benefit from the smart metering upgrades.*

The AEMC's reforms to accelerate smart meter uptake will likely exacerbate this issue and therefore it is appropriate to consider the reclassification of metering services for 2024-29.

The issue of socialising the costs of this transition towards smart metering was discussed with our RRG. This engagement session included a proposal to accelerate the recovery of the MAB and a comparison of various outcomes under the current ACS classification against a prospective change to a SCS classification (and revenue cap form of control) which we indicated was our preferred option. Some of the key observations included:

- Socialising metering costs evenly across all SCS customers results in a lower cost per customer;
- Non-Type 5 & 6 customers would see an increase in overall cost, noting smart metering costs are likely socialised across Type 5 & 6 customers by retailers currently; and
- As the metering asset base recovery is accelerated and metering opex reduced for churn, the SCS metering price impact reduces materially over the 2024-29 period.

Our RRG acknowledged that a reclassification would require transitioned customers to share in the costs of metering assets/services not provided to them. However, on balance they indicated this concern is outweighed by the price risk to the remaining customers and therefore supported socialising metering costs across all customers through a reclassification to a SCS.

5.2.2 Proposed control mechanism for SCS metering

In our January 2023 Proposal we accepted the decisions in the AER's Final Framework and Approach to apply revenue caps to SCS and price caps to ACS. We also proposed to apply the AER's final position on the side constraint mechanism and the formulae to give effect to the control mechanisms set out in the Final Framework and Approach.

The AER's draft decision made a number of amendments to improve the transparency of the revenue cap formulae, give effect to its final position on side constraints and amend the ACS formulae to accommodate a true-up for metering service opex amongst other minor changes. We accept the AER's draft decision noting that further updates will be required if Type 5 & 6 metering is re-classified from ACS to SCS as proposed.

In preparing our Revised Proposal, we have had several discussions with the AER on how the revenue cap control mechanism formulae could be updated for a re-classification of metering services. We understand the AER's preference is for legacy metering services to be treated as a separate sub-component of total SCS expenditure and the outputs of "main SCS" (i.e., SCS excluding metering) and legacy metering SCS PTRMs be consolidated at the total level for the purposes of the AER's constituent decisions.

This means there will be two different smoothing processes to accommodate different priorities in smoothing across main SCS and legacy metering SCS. The AER also sets out its expectation that legacy metering SCS revenue should be recovered across all customers as a separate fixed charge component that the TSS

[32] AEMC, Final Report – Review of the regulatory framework for metering services, 30 August 2023, p.96

should be updated to introduce. This would be to maintain transparency and accommodate any true-ups or pass-throughs that may be required.

We agree with the AER's guidance and principles for incorporating legacy metering into SCS, particularly the need to balance transparency with pragmatism. However, we propose an alternate means for giving effect to the reclassification of metering.

Specifically, the AER's recommended approach requires the calculation of an additional Total Annual Revenue (TAR) specifically for metering and in addition to the TAR calculated for main SCS services. The calculation of a metering TAR essentially replicates the formula used to calculate the main SCS TAR. The total TAR would involve combining the legacy metering SCS TAR with the main SCS TAR. We propose a less complicated approach is taken whereby legacy metering revenue is incorporated in the main SCS TAR via an adjustment factor.

There are currently adjustment factors for incentive scheme revenue ("I"), overs and unders balancing ("B") and cost pass-through amounts ("C"). We propose a legacy metering adjustment factor is added to the formulae (an "M" factor). This would reduce the complexity of implementing a change in classification by avoiding the need to separate Distribution Use of System Charges (DUOS) in billing systems i.e., main SCS DUOS and metering SCS DUOS. On this, we are yet to fully scope the ICT changes required to implement the AER's preferred approach and whether it is feasible or cost-effective.

Our alternate approach would still allow for the separate smoothing of legacy metering revenue as the AER has discretion in how the adjustment factor is calculated (in this instance by replicating the approach taken to calculating and smoothing revenues in the PTRM). DNSPs would also still be able to adjust their TSS's, for the AER to review and approve accordingly, to specify how this component of revenue will be recovered from customers.

We note this would not allow for separate management of an overs and unders account. However, in our view there is no practical value in doing so given we propose to recover legacy metering revenue on a per customer basis. The level of forecasting error in customer numbers is historically low (0.3% per annum over the five-year period 2019-2023, inclusive) and therefore the contribution of metering to over or under recoveries is likely to be immaterial (in the order of cents per customer). Instead, for reporting purposes the SCS revenue attributable to metering could be reported by networks, similar to incentive scheme revenue in the Benchmarking RIN currently, so that the AER is able to separate it for reporting and benchmarking purposes as required.

Our proposed approach also avoids a number of potential compliance issues associated with duplicating the approach taken to deriving TAR an AAR amounts and setting tariffs for SCS legacy metering in accordance with the Pricing Principles in the Rules. These issues include the determination of long run marginal cost estimates for metering SCS (6.18.5), stand-alone and avoidable costs for metering SCS (6.18.5) and the application of the side constraint mechanism to metering SCS (6.18.6)

Under our proposed approach, the metering SCS would be folded into main SCS services for the purposes of Rule compliance, noting that the side constraint formula would also need to be adjusted for the M-factor. For these reasons we propose our alternate method for amending the revenue cap control mechanism formula for giving effect to a change in service classification for metering.

We would welcome further engagement with the AER on this proposal to develop an approach that is proportionate and promotes transparency and pragmatism.

5.2.3 Setting SCS metering tariffs

We propose to recover the annual Metering revenue requirement from our Small Low Voltage tariff class. We propose to limit the recovery of Metering from this tariff class as we believe this best maintains cost-reflectivity. The Metering costs being recovered under this service relate to customers in this tariff class alone and are currently being paid by customers in the tariff class under an ACS service.

Within the Small Low Voltage tariff class, each tariff with a daily access charge charging parameter will attract a uniform Metering increment to their SCS fixed charge.

The uniform fixed charge Metering increment will be calculated as the annual Metering revenue requirement divided by the sum of customers on each tariff with a daily access charging parameter within the Small Low Voltage tariff class.

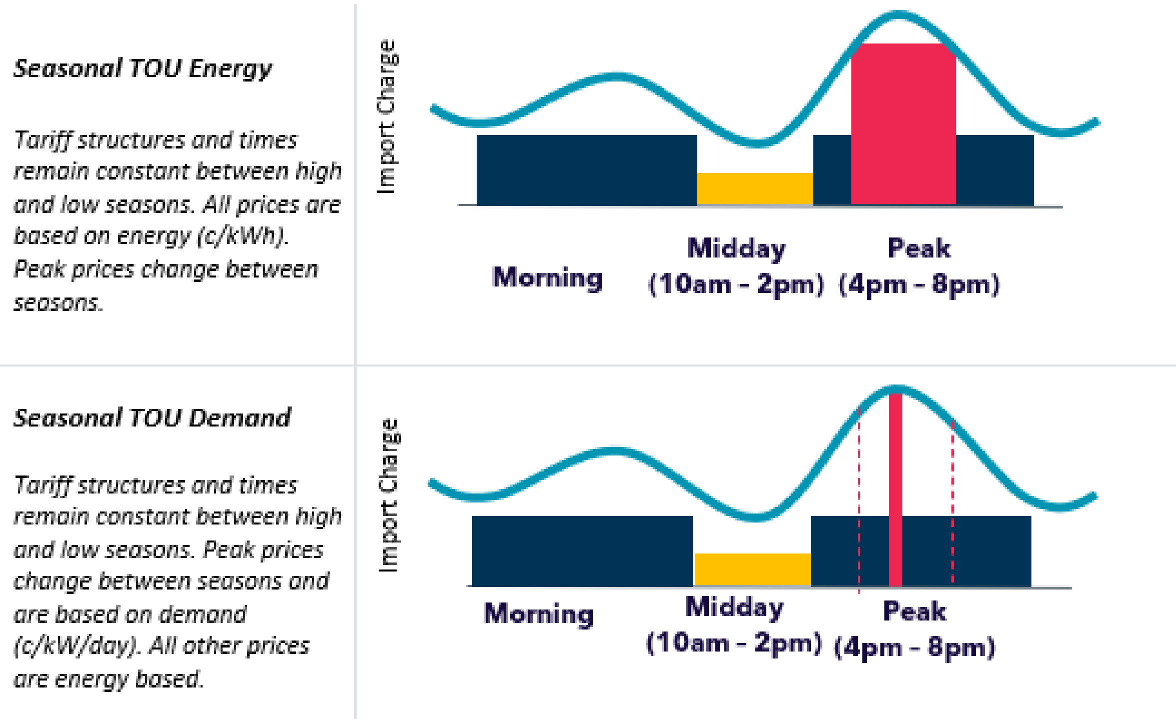
5.3 Residential and small business tariff reform

Our proposed tariff reforms for residential and small business customers relate primarily to our Seasonal Time of Use Energy (Seasonal TOU Energy) and Seasonal Time of Use Demand (Seasonal TOU Demand) tariffs. The key changes are:

- to assign new customers and all customers with a smart meter by default to the Seasonal TOU Energy tariff, but allow them to opt-out to the Seasonal TOU Demand tariff;
- to introduce a solar soak period in the middle of the day for our Seasonal TOU Demand and Seasonal TOU Energy tariffs, to address the imbalance at those times between residential load and supply from distributed generation;
- to retain our existing peak period, but to include the flexibility to extend it by one hour in response to EV load, subject to an objectively defined trigger; and
- to introduce a new secondary tariff that comprises and export reward and an export charge.

We illustrate the proposed structure of our Seasonal TOU Energy and Seasonal TOU Demand tariffs in the figure below, before explaining each of the above reforms in more detail.

Figure 27: Proposed tariff structures



5.3.1 Tariff assignment policy

Endeavour Energy developed the 2019-24 TSS assignment policy with the support of stakeholders. The introduction of our Seasonal TOU Energy and Seasonal TOU Demand cost-reflective tariffs was a significant milestone in efficient tariff reform.

Stakeholders supported our adoption of the Seasonal TOU Demand tariff as the default cost-reflective tariff for the 2019-24 period. However, we have since received feedback from a majority of retailers that demand-based tariffs are, in their view, more complex and less marketable to customers.

In response to this feedback, our Seasonal TOU Energy tariff will now be our default cost-reflective tariff option, where customers can still choose to switch to the demand-based tariff.

With many reform programs, there is the risk of creating “winners and losers”. To mitigate the potential risk to customers we introduced:

- transitional tariff structures that transition to cost-reflectivity over time;
- a discount to cost-reflective tariffs relative to our non-cost reflective tariff option. This discount applies to 90% of our customers; and
- an “opt-out” assignment policy that allowed customers defaulted to the cost-reflective tariff to opt-out to a non-cost-reflective tariff option.

Nevertheless, large numbers of retailers continue to exercise their ability to “opt-out” of more efficient tariff options on behalf of customers. For this reason, we have considered whether a strengthening of our tariff assignment policy is appropriate at this stage of the tariff reform process.

We carefully weighed divergent views of customers, retailers and stakeholders in developing our proposal.

Our Customer Panel were supportive of cost-reflective tariffs and keen to make use of opportunities to better manage and reduce their electricity bills. The majority (55%) also initially favoured strengthening our assignment policy. However, in our more recent engagement with our Customer Panel the majority (60%) favoured an “opt-in” approach to tariff assignment. This may reflect growing concerns with cost-of-living pressures and their ability to respond to these price signals.

Our expert stakeholders on the other hand were more strongly (71%) in favour of strengthening our policies consistent with the aims of policymakers.

We therefore propose that all residential and general supply customers with enabling smart metering will be assigned to our Seasonal TOU Energy tariff.

These customers will be allowed to “opt-out” of the Seasonal TOU Energy tariff to our Seasonal TOU Demand tariff, however the option to opt-out of cost-reflective pricing will be removed.

This will accelerate the transition to cost-reflective tariffs for both new and existing customers, and limit retailers’ ability to opt-out of cost reflective tariffs. Retailers remain welcome to develop retail offerings that manage the network costs that arise from these efficient network tariff structures, while meeting the needs of customers.

Our January 2023 TSS submission included the proposal to transition customers onto our Seasonal TOU Energy tariff via a 24-month transition period under the proposed assignment policy. This was proposed to mitigate any adverse impacts on customers and allow more time for customers to adapt to cost-reflective pricing options.

As outlined in section 3.8, at our June 2023 Customer Panel over two thirds (67%) of Customer Panel participants preferred retailers are offered a 12-month transition to time-of-use network tariffs, largely as they wanted to access these tariffs to save money as soon as possible by changing the time of day they consume electricity.

Therefore, to manage adverse customer impacts, our proposed assignment policy will now occur over a 12-month transition period, i.e.:

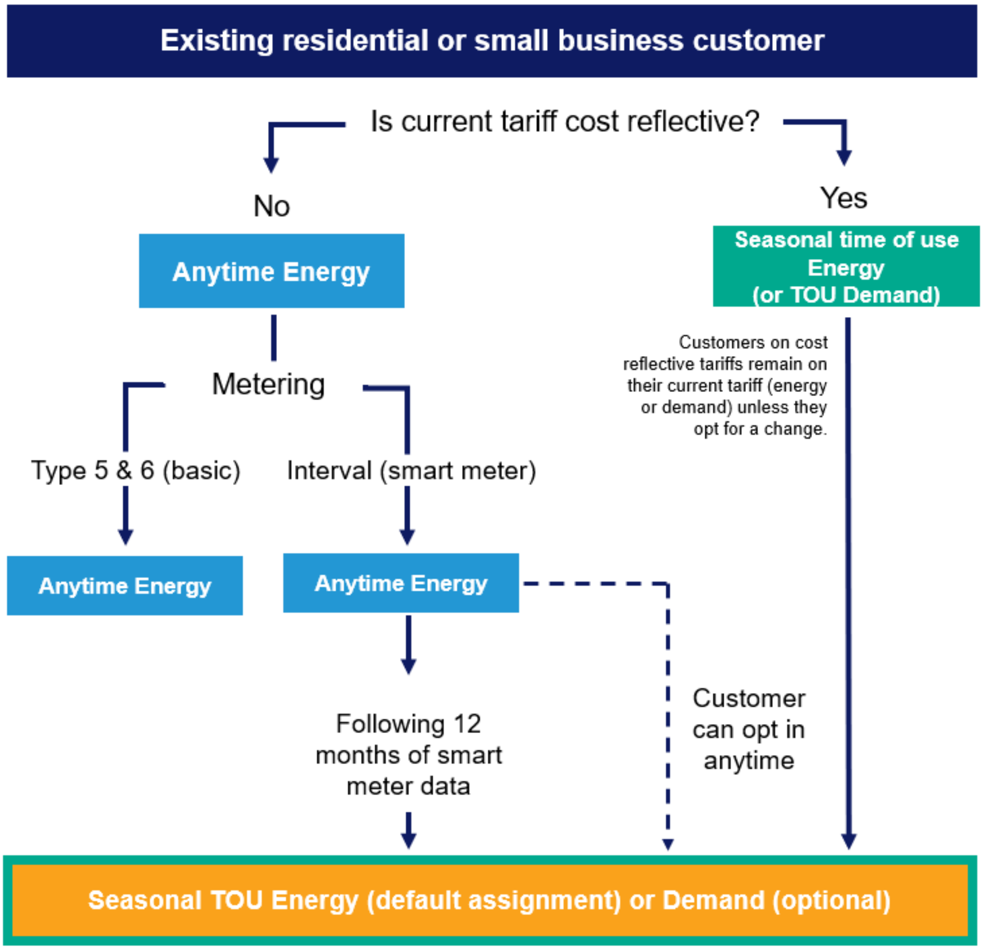
- after obtaining a smart meter a customer will remain on their existing tariff for the next 12 months;[33] and

[33] Note that re-assignments will occur on a bulk, rather than ‘real time’, basis meaning customers could remain on their existing tariff for a period longer (but not shorter) than 12 months.

- they will then be assigned to the Seasonal TOU Energy tariff.
- This period will provide customers an opportunity to understand, monitor and adjust their energy usage with the benefit of smart metering.

While all new customers will be assigned to the Seasonal TOU Energy tariff by default, the figure below, illustrates our proposed assignment policy for existing residential and general supply customers currently supplied on the Anytime Energy tariff.

Figure 28: Assignment policy for existing customers on an Anytime Energy tariff



5.3.2 A new solar soak period

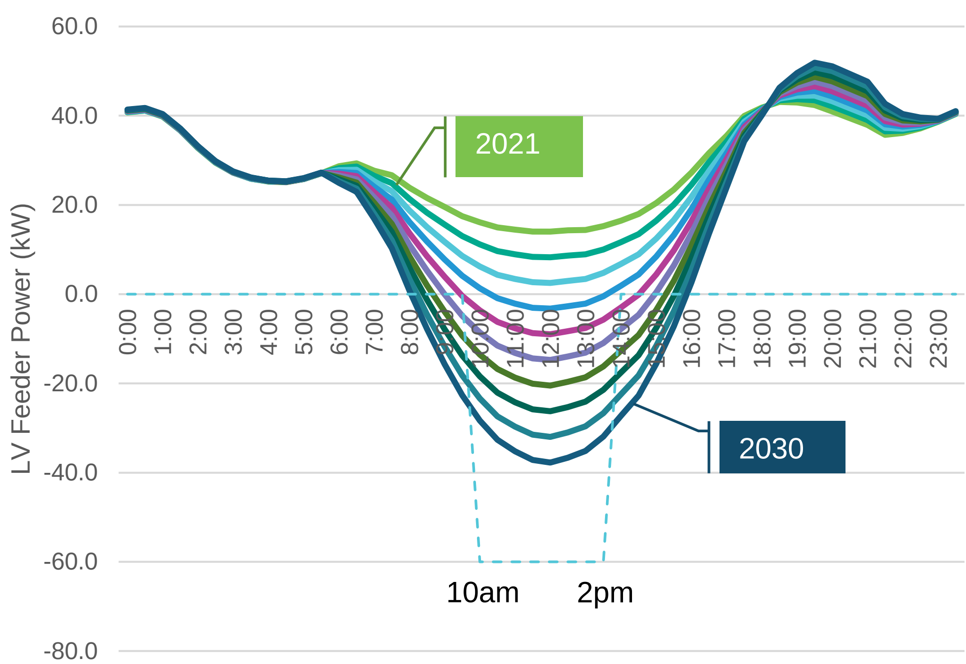
Imbalances between low residential load and high distributed generation in the middle of the day are causing voltage fluctuations in residential areas, which are becoming increasingly costly to manage.

We therefore propose to introduce a solar soak period in the middle of the day with a very low energy price that encourages customers to shift discretionary load to the middle of the day, i.e., to soak up excess solar PV generation. We refer to this period as a 'solar soak period'.

The solar soak period will help us to avoid the costs that arise from the imbalances between demand and supply during this period and enable all customers – irrespective of whether they invest in CER – to contribute to the transition to a clean energy system.

We forecast that the imbalance between low load and high supply is highest between 10am and 2pm, as illustrated in Figure 29.

Figure 29: Forecast impact of PV uptake on our charging windows



We propose, therefore, to include in our Seasonal TOU Energy and Seasonal TOU Demand tariffs a solar soak charging window between 10am and 2pm each day. A low energy price will apply during the solar soak period.

5.3.3 Flexibility to extend the peak period

Temperature has been the underlying driver of peak demand on our network because it drives customers' use of energy intensive cooling (air-conditioning) and heating appliances.

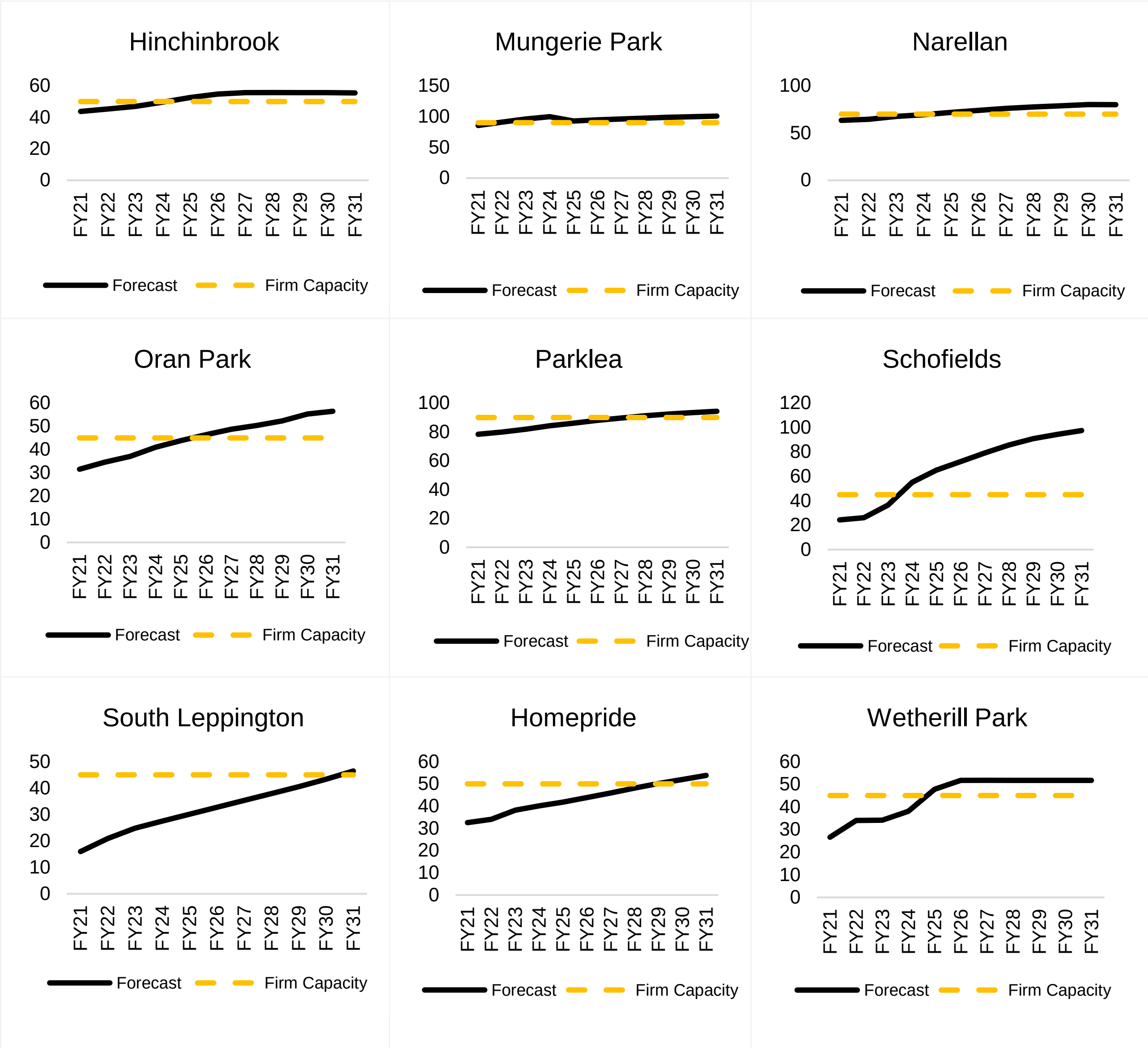
More specifically, air conditioner load during periods of extreme hot temperatures is the primary driver of peak demand on our network, e.g., every system peak demand event in the last decade occurred in the summer months.

It is for this reason that our Seasonal TOU Energy and Seasonal TOU Demand tariffs include a seasonal element. Although the charging windows are the same in the high season (1 November to 31 March) and low season (1 April to 31 October), a high peak price applies in the high season

We examined the timing of peak demand at distribution zone substations that are approaching capacity, i.e., the demand that is more relevant to future costs.

We identified nine distribution zone-substations where demand is approaching their rated capacity over the next five to ten years. Figure 30 shows the forecast maximum demand at these distribution zone-substations in black, as compared with their current rated capacity (in orange).

Figure 30: Forecast maximum demand in constrained zone substations



A peak charging window that does not coincide with the timing of peak demand at these zone substations will result in us providing inefficient price signals that exacerbate peak demand and potentially increase our network costs.

We therefore examined the timing of peak demand events[34] at these substations over the five-year period 2018-22. This analysis is presented at Figure 31.

[34] A peak demand event is defined as a timed interval where demand is within 5% of annual peak demand at the substation.

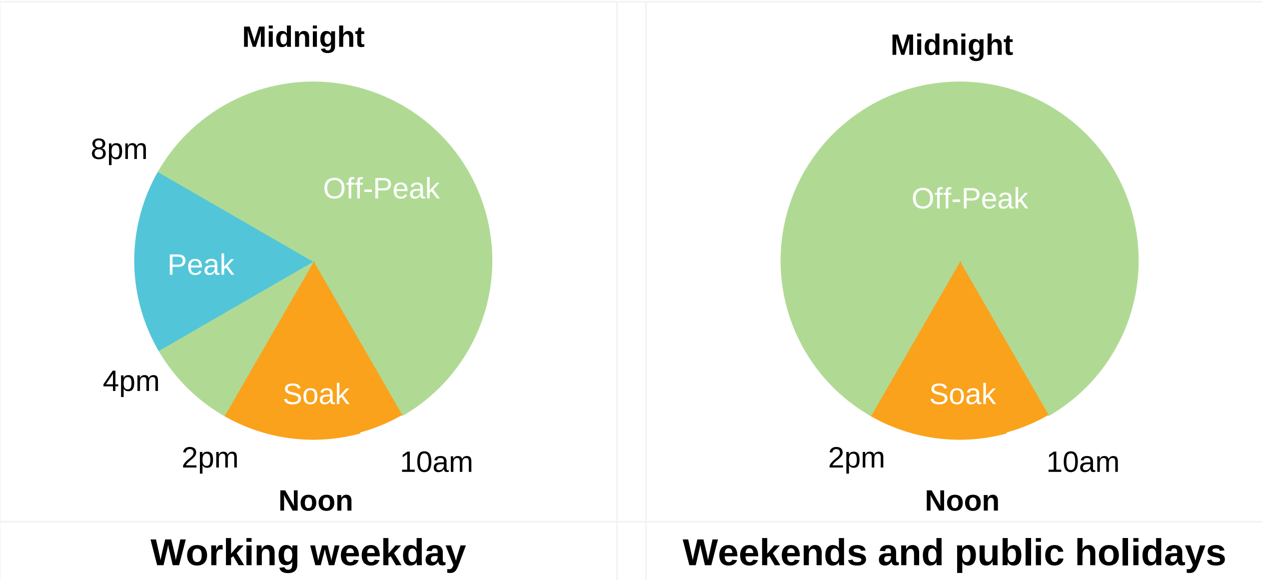
Figure 31: Forecast maximum demand in constrained zone substations

As a result of this analysis we propose to maintain:

- our existing high and low season definitions; and
- our peak import charging window of 4pm to 8pm weekdays.

Our proposed charging windows therefore remain unchanged, but for the inclusion of a solar soak period, as presented in Figure 32. However, we propose to include flexibility to extend the peak period to apply from 4pm to 9pm, as described below.

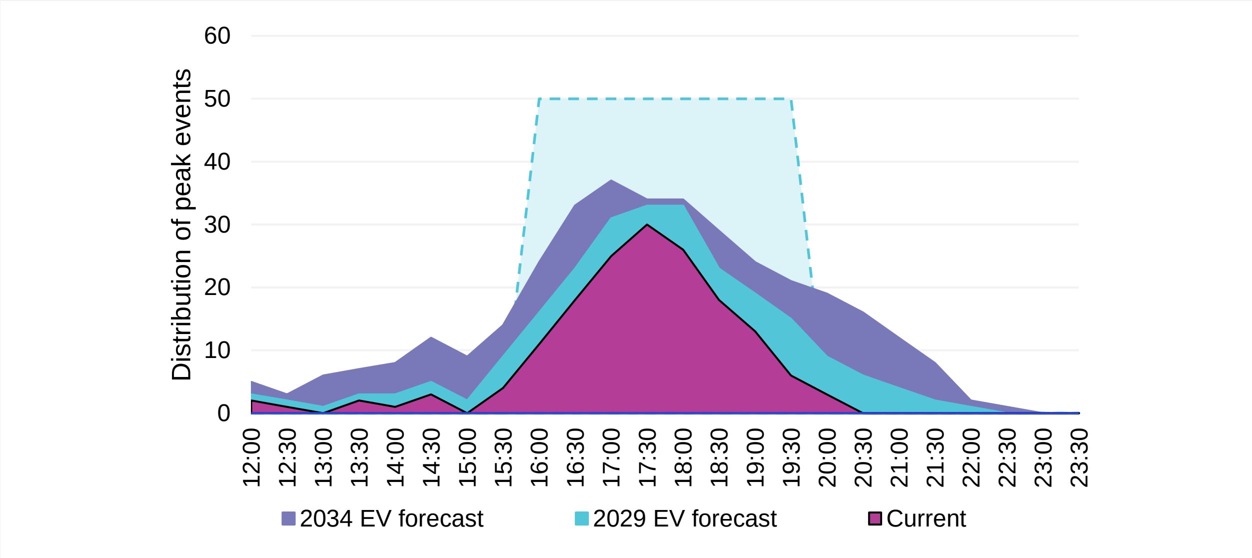
Figure 32: Our proposed charging windows



5.3.4 Flexibility and trigger

We expect customer uptake of Electric Vehicles (EV's) to have an impact on the timing of our future peak charging windows. Our analysis suggests that EV's will create additional peak events beyond our proposed 4-8pm window by the final year of the TSS period (2029).

Figure 33: Forecast impact of EV's on charging windows



There are pros and cons to extending the peak charging window, i.e.:

- inefficient peak pricing signals are sent to customers before the penetration of EV's becomes material;
- extended peak charging windows diminish both the economic signal and our customer's ability to respond to the pricing signal; and.
- if uptake exceeds our expectations, we risk under-signalling the economic impact of EV charging on our network.

For this reason, we propose that our TSS includes an option to extend our peak window to apply from 4pm to 9pm (rather than 4pm to 8pm), if EV uptake and consumption profiles exceed our expectations and prove to have a material impact on demand, and therefore our future costs.

In our view, the inclusion of flexibility in a TSS should be contingent on an objectively defined trigger. We therefore propose to extend our peak window to apply from 4pm to 9pm only if the timing of system peak demand, as reported in our Regulatory Information Notice (RIN), occurs after 8pm.

5.3.5 A new secondary two-way tariff

In addition to the solar soak period described above, we also propose to introduce new two-way tariffs for residential and small business customers that comprise an export charge and an export reward. These two-way tariffs will signal to exporting customers the network benefits that arise from:

- managing their exports in the middle of the day, e.g., by shifting load to the middle of the day to increase self-consumption, storing generation in a battery or installing west-facing panels; and
- exporting during the evening peak period, when customers should be rewarded for their exports because it frees up network capacity.

Our existing tariffs only signal the costs of additional load during peak demand through peak charges. Providing cost reflective prices and rewards for two-way flows is an opportunity to empower choice and control over customers' energy use and harness the full network value of customer investments in CER.

To this end, we expect our $76 million CER integration expenditure program to unlock 6,000 GWh of renewable energy that would otherwise be lost through curtailment.

To facilitate export pricing, we propose two-way flow tariffs to signal to customers both the costs and benefits of their energy consumption and generation behaviour by using a simple, transparent, and predictable combination of prices and rewards for flows in either direction.

We propose that an export charge and export reward is offered in the form of a ‘secondary tariff’ that would apply alongside our Seasonal TOU Energy and Seasonal TOU Demand tariffs.

Figure 34: Proposed charge and reward structure for two-way prosumer tariff

Export Charge & Reward (“Prosumer”)

Tariff structure remains constant between high and low seasons. Peak export reward will change based on seasonal import LRMC (as a negative price). Export charge is based on export LRMC.

The export charge will apply to exported energy above 1,750 kWh pa. Below 1,750 kWh pa is free.

We received strong support from our Customer Panel (81% in favour), RRG and Deep Dive stakeholders (90% in favour) to introduce export rewards and charges.

This analysis indicated that export prices were appropriate for low voltage customers in this regulatory control period due to the:

- future network costs that will be caused by higher levels of exports; and
- relatively low proportion of intrinsic hosting capacity that is not currently used for exports on the existing network.

The remainder of this section contains a summary of our process for identifying the need for export prices and our proposed implementation and transition strategy for export prices.

5.3.6 Basic export level

Over the 2024-29 and 2029-34 regulatory control periods,[35] we are required to offer a basic export level to all export customers.[36] Retail customers can export onto our network up to the basic export level without incurring an export charge.[37]

The basic export level is closely linked to the intrinsic hosting capacity, which reflects the export capacity of our network in its current state.[38] That is, the intrinsic hosting capacity is the baseline level of reverse power flow that can be supported without the need for additional network expenditure.

Existing export hosting capacity on our network reflects the development of our network to provide customers with import services only. To the extent that different parts of our network can support varying

[35] See: definition of the ‘tariff transition period’. The Rules, cl. 11.141.1.

[36] The Rules, cl. 11.141.13(a).

[37] AEMC, *Access, pricing and incentive arrangements for distributed energy resources | Final determination,* August 2021, p 101.

[38] AER, *Export tariff guidelines*, May 2022, p 12.

levels of import demand, there is also varying capacity to service exports across different parts of our network.

By offering each customer a basic export level that is linked to the intrinsic hosting capacity of the network, we ensure customers only pay export charges for their contribution to aggregate exports that exceeds the intrinsic hosting capacity.

Ideally, the basic export level would vary with respect to:

- the geographic area of network in which the connection occurs, i.e., a location specific basic export level; and
- changes over time in the size and number of embedded generators and storage units installed in the area of the network in which the connection occurs.

In practice, the application of postage stamp pricing for our two-way tariffs lends itself to uniform basic export level across the network, rather than a location specific basic export level. In addition, we wish to provide our export customers with certainty regarding the costs of installing solar PV assets over the 10-year tariff transition period. By consequence, we intend to offer all export customers a basic export level that does not change throughout this period.

We therefore apply a uniform basic export level to all customers across our network for the 10-year tariff transition period.

The basic export level is calculated using a model of our network that simulates two-way flows across our low voltage assets. This model determines the expected export curtailment that occurs on our network under a range of customer specific assumptions, e.g., size and uptake of CER assets. We use this network simulation model to quantify the impact of different assumed levels of exports per customer on total curtailment arising from expected future solar PV installations given the current state of the network.

This process is described as follows:

1. Forecast total future export customers by applying expected solar uptake on our network, consistent with AEMO, to our network's current level of solar penetration.
2. Assume different capacity size of installed solar assets, i.e., 1 kW, 2 kW, etc.
3. Run the network simulation model to determine total curtailed exports given forecast penetration and assumed capacity size absent any network investment to increase export hosting capacity.

The results of this process are shown in Table 8, with total curtailment increasing rapidly for assumed export capacity in excess of 2 kW.

Table 8: Expected export curtailment across a range of assumed solar asset capacities

Assumed export capacity (Inverter size)	Total curtailed exports (GWh)	Growth in curtailed exports (GWh)
0 kW	0	-
1 kW	7.6	7.6
2 kW	24.7	17.1
3 kW	67.0	42.2
4 kW	144.2	77.2

The results of this process indicate that, absent network investment to support two-way flows, our anticipated export service standard will deteriorate substantially when export capacity exceeds 2 kW per customer.

In light of the practical divergence of the basic export level and the intrinsic hosting capacity, this approach ensures that the basic export level is determined with explicit reference to expected export curtailment and export service standards.

While the AER accepted our proposed (January 2023) two-way tariff structure, we were asked to consider converting our proposed export charge from a demand-based structure to an energy-based structure. We accept that there are simplicity and consistency benefits of this tariff structure and have changed our proposed two-way tariff structure in accordance with this request for consideration.

The AER accepted our proposed 2kW basic export level in their draft decision, but to give effect to an energy-based export charge the basic export level must be converted to a kWh basis.

To do this we used the exported energy of a representative sample of those customers that exceed the 2kW capacity limit in the 10am to 2pm window. For each customer in the sample, we took the average of their total export energy in this window less their energy export when their output is greater than 2kW. This provides the average annual energy export amount where output capacity used by the customer is lower than 2kW. The average of this value is 1,750kWh per annum.

We therefore define the basic export level to be 1,750 kWh per customer per annum[39].

5.3.7 Price levels

We propose to set an export reward by reference to import LRMC and an export charge by reference to export LRMC. We describe our estimates of import and export LRMC in section 7.2.

The export charge will apply to the level of energy – measured in kWh – exported above the basic export level during the solar soak period each month, i.e., between 10am and 2pm.

The export reward will apply to the level of energy – measured in kWh – exported during the peak import period, i.e., 4pm to 8pm in the evenings.

5.3.8 Tariff assignment and transition strategy

We propose that the assignment of customers to our two-way tariff is on:

- an opt-in basis for existing export customers; and
- an opt-out basis for new or upgrading export customers, from 1 July 2025 (and opt-in prior to 1 July 2025).

This is consistent with the feedback we have received from customers. The majority of our Customer Panel (who are existing customers) preferred an opt-in approach to export tariffs (53%)[40]. Our stakeholders were similarly supportive of an opt-in approach (57%).

In balancing this feedback, we consider a stronger policy is appropriate for new and upgrading customers. These customers should be presented with cost-reflective information upon which to inform the decision they are actively making with regards to their investment in DER. Whilst existing customers should have greater flexibility until such time as they are considering whether to replace or upgrade their existing systems.

We define an existing export customer to be any customer with installed export capacity before 1 July 2024, i.e., the start of the upcoming regulatory period.

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[39] Endeavour Energy has displayed basic export level threshold on a kWh per annum basis. In practice, this annualized consumption threshold will be calculated on a daily basis and applied to the billing period.

[40] 28% of the remaining customers preferred mandating, whilst 19% preferred deferring export tariffs until at least 2030.

No existing residential or small business export customers will be assigned to a two-way tariff during the 2024-29 regulatory control period.[41] However, they can opt-in to a two-way tariff any time after 1 July 2024 and can also subsequently opt-out of this two-way tariff.

This approach will provide flexibility for existing export customers to select the pace of their transition.

We anticipate that the presence of the export reward during the demand peak period in this transitional two-way tariff may provide sufficient incentive for these customers to opt-into this tariff and manage their exports to provide network support during the peak import period, e.g., by installing a behind the meter battery.

All new residential and small business export customers will be assigned to a cost-reflective two-way tariff from 1 July 2025. However, they can opt-out of a two-way tariff for the remainder of the 2024-29 regulatory control period. We intend to remove this opt-out clause at the start of the 2029-34 regulatory control period, which was supported by stakeholders.

Dedicated two-way flow connections, i.e., community and grid scale batteries, will not be able to opt-out of their two-way flow tariffs.

Our assignment policy is summarised below.

Table 9: Summary of two-way tariff transition strategy assignment policy – residential and small business

Customers	Prior to 1 July 2025	After 1 July 2025	2029-34 regulatory control period
New residential and small business export customers (post 1 July 2025)	*Opt-in option to cost-reflective two-way tariff.*	*Assigned to cost-reflective two-way tariff with opt-out clause.*	*Assigned to cost-reflective two-way tariff with no opt-out clause.*
Existing residential and small business export customers (pre 1 July 2025)	*Opt-in option to cost-reflective two-way tariff.*		*Re-assigned to cost-reflective two-way tariff with no opt-out clause.*
Any commercial dedicated two-way flow connection, e.g., community or grid-scale battery	*Assigned to cost-reflective two-way tariff with no opt-out clause.*		

In addition to the transitional assignment policy for two-way tariffs, we have also developed a transition strategy for the basic export level. As per the Rules, we intend to offer all export customers a basic export level for the 2024-29 and 2029-34 regulatory control periods,[42] however beyond the 2029-34 period we intend to remove the basic export level for all exporting customers.

5.4 Grid connected battery tariffs

In this section we describe our proposed tariffs for grid connected batteries that connect to the low or high voltage network, and comment on the relevance of community battery initiatives.

[41] AEMC, *Access, pricing and incentive arrangements for distributed energy resources | Final determination*, August 2021, p vi.

[42] The Rules, cl. 11.141.12.

5.4.1 Low voltage grid-connected battery

The advent of grid-connected batteries and the sophistication of their operators presents a prime opportunity to avoid network costs through the application of highly efficient price signals that promote efficient network utilisation.

Our proposed tariff structure for grid-connected batteries promotes economic efficiency during peak demand events through the introduction in the peak demand period of a:

- marginal cost based import charge that encourages a battery operator to manage its demand; and
- marginal cost based export reward that encourages a battery operator to export energy, thereby freeing up capacity on higher levels of the network.

Similarly, economic efficiency is promoted during peak export events through the introduction in the peak export period of a:

- marginal cost based export charge that encourages a battery operator to manage its exports; and
- zero price for imports that encourages a battery operator to shift load to those times, otherwise known as 'solar soaking'.

We have elected not to reward customers for increasing load during peak export events due to the risk that customers increase load by operating appliances that provide no amenity at that time, for example, by leaving lights on during the middle of the day. A consistent approach is proposed for grid-connected batteries by using a very low (or zero) price, rather than a reward, to encourage load shifting into peak export periods.

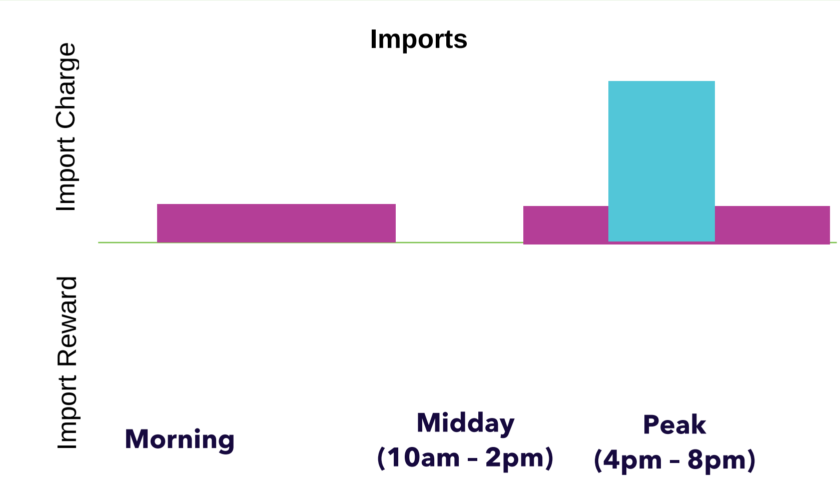
Just like all other customers, battery connections should contribute to the recovery of residual costs across the network. This reflects the battery's use of the entire network to import electricity and for, potentially, accessing wholesale and ancillary service markets. Residual costs are recovered through a fixed charge and variable import charges (outside of the solar soaking window).

All variable prices are levied on a per kilowatt-hour (kWh) basis. This reflects feedback from battery operators identifying potential scope to manipulate a demand-based export reward, that is, to receive a financial reward without a commensurate benefit to the network.

Figure 35: Proposed charge and reward structure for two-way low voltage grid connected batteries

LV Grid Battery (Imports)

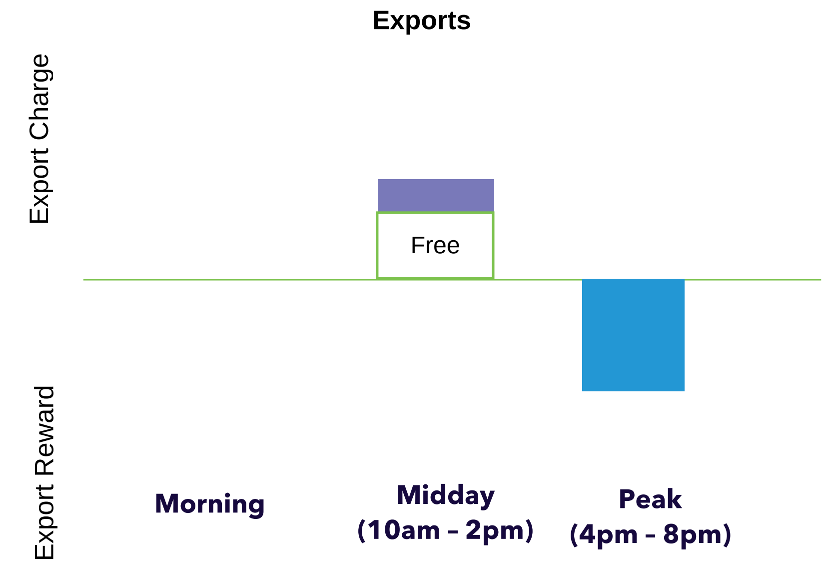
Tariff structure remains constant across high and low seasons. Peak import charges change based on seasonal import LRMC.



LV Grid Battery (Exports)

Tariff structure remains constant between high and low seasons. Peak export reward will change based on seasonal import LRMC (as a negative price). Export charge is based on export LRMC.

The export charge will apply to exported energy above 1,750 kWh pa. Below 1,750 kWh pa is free.



Based on our indicative FY25 prices for the low-voltage grid connected battery tariff, we expect the network bill of battery operators to be in credit if they charge their battery during our solar soaking and off-peak windows while exporting 100% of their output during our afternoon peak window.

Table 10: Indicative network bills under the low voltage grid connected battery tariff

	Indicative Annual Network Bill *(Assumes battery exports 100% of energy in peak window)*	
Proportion of battery import during solar soak window *(with balance of import in other non-peak windows)*	**60 kWh Battery**	**445 kWh Battery**
100%	-$335	-$5,899
75%	-$247	-$5,252
50%	-$160	-$4,604
25%	-$73	-$3,957
0%	$14	-$3,310

To be eligible for the low voltage grid connected battery tariff, the battery must be connected to the low voltage network and must consume no more than 160 MWh per annum, consistent with our small low voltage tariff class.

5.4.2 High voltage grid-connected battery

We propose to offer high-voltage grid-connected battery tariffs as a site-specific tariff, which will enable us to better align the tariff to reflect locational constraints.

The key distinction in the tariff for batteries connected to the high voltage network is the absence of an export charge and a much lower (or zero) price when exports are most prevalent. This is because exports do not significantly exceed localised imports on the high voltage network, such that there are no ‘peak export events’ that impose costs on the network.

In addition to providing an export reward during the peak demand period, the tariff structure also includes the flexibility to provide a small export reward in all time periods. This reward may be used to reflect the avoided transmission costs that result from reduced import demand from the transmission network[43]. It may also be used to return any energy based jurisdictional scheme charges recovered from the battery from its import charges. This ensures the battery provider contributes to the jurisdictional scheme on the energy it consumes (i.e., the batteries import to export losses).

Finally, residual costs are recovered through a fixed charge and variable import charges. Residual costs are not returned to the battery operator through the export reward.

Figure 36: Proposed charge and reward structure for high voltage grid connected batteries

[43] Subject to the payment of avoided TUOS to the battery provider under 5.3AA (h) of the Rules.

5.4.3 Community batteries

Community battery projects are expected to emerge in the coming years as a way of cost-effectively managing two-way flows within the low voltage distribution network. By providing the opportunity for local network customers to 'store' local network flows to be used during demand peak times, a community battery can address problems arising from solar peak events while reducing peak import costs.

A key challenge for distributors is how best to allocate network benefits from the community battery between the battery operator and the community battery participants. Some distributors have been exploring local use of system charges, which provide a network tariff discount for local energy flows. However, these tariffs generally require complex accounting of the exports and imports of community battery participants and operators and result in challenges when those flows do not align.

It follows that our approach is to provide the network value of community batteries directly to the community battery operator through the network tariff structure, who can than determine how that value is shared with community battery participants. This approach provides flexibility for the sharing of value to be based on the allocation of costs and risks between the community battery provider and participants that best suits their circumstances.

The network tariff discount during peak export periods, and the rewards when exporting at other times, reflect the network value that operation of a community battery delivers.

We consider this approach is consistent with the Rules and promotes the adoption of cost-reflective tariffs. In the future, and potentially in trials, potential improvements for investigation include:

- reducing the level of residual costs recovered from variable import charges outside the peak demand period;
- defining peak demand and peak export periods in a dynamic manner; and
- using location specific estimates of LRMC as the basis for price signals and rewards.

5.5 Embedded Network tariffs

We describe the opportunities and challenges presented by embedded networks in section 4.4.

We explain in that section that we want embedded networks to be created because they are efficient and benefit the customers within them, not because those customers benefit – at the expense of other customers – from making a much lower contribution to recovering the cost of our existing network.

This inappropriately low contribution arises because, at present, embedded networks are treated as a single customer that pays a single, low fixed charge.

The core of the issue with our current approach is that an embedded network is assigned to a large customer tariff based on the aggregate annual energy consumption of its "child" connection points. We do not believe this is equitable, since the embedded network is not an individual business or industrial customer, it is a collection of SME businesses and residential customers.

We have identified 389 embedded networks that are currently connected to our network, which makes up over two per cent of all energy consumed on our network. Of the 389 embedded networks identified, 256 are large connections consuming greater than 160 MWh per annum, with the vast majority (248) being low voltage sites and a minority (8) sites that are HV connected customers.

Unfortunately, we have no visibility over the connections within an embedded network, although it appears that the majority of child NMIs at the low voltage sites are small businesses in the context of shopping centres and residential customers in the context of apartment buildings and developments. The HV sites do not appear to be aggregating residential and small business sites and as such, we do not believe an embedded network tariff is required at this time.

We received feedback from the Caravan and Camping Industry Association of NSW (CCIA NSW) recommending the exemption of:

- holiday parks, where the supply of electricity was seen as incidental and temporary; and
- residential land lease communities where legislation prevents operators from profiting from the sale of electricity.

We have considered this feedback and assessed that, in the case of holiday parks, limiting the application of the embedded network tariffs to sites greater than 160 MWh per annum will address concerns that incidental and temporary electricity is unfairly captured. With respect to land lease operators, embedded network profitability is not the issue we are seeking to address, rather we seek a more equitable contribution to residual, or "shared", network costs for those customers inside the embedded network relative to similar customers outside of an embedded network.

Any proposed solution to the issues presented by embedded networks should address the unfair savings of embedded networks while also recognising the network benefits associated with embedded networks.

In response to feedback on our proposed embedded network tariff in our January 2023 TSS, we accept that it is possible that the formation of an embedded network can result in an offsetting and incremental opex saving in expenditure areas such as vegetation management, maintenance and emergency response.

To estimate this saving, we have used the AER's opex model to calculate the reduction in opex that results when circuit line length growth is curtailed by the formation of an average embedded network.

This revision reduces the expected impact of the tariff on embedded network operators and their customers relative to our initial proposal.

We therefore propose to implement a LV embedded network tariff that includes an additional demand charge to our standard demand-based tariff (N19). Feedback from other stakeholders support the introduction of an embedded network tariff for the 2024-2029 regulatory period.

The revised calculation of the additional demand charge for the embedded network tariff is outlined in the table below.

Table 11: Calculation of additional demand charge for our proposed embedded network tariff

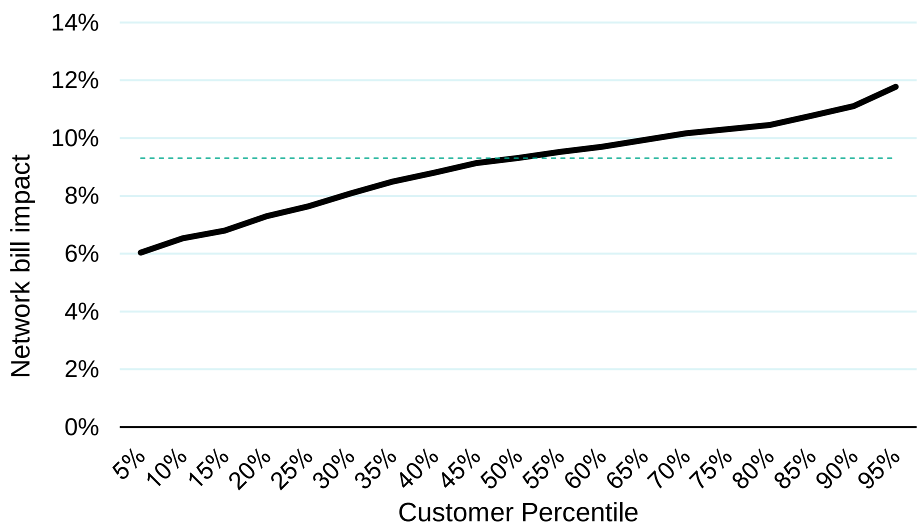
Calculation of additional demand charge for proposed embedded network tariff		
Target residual cost recovered from a large LV customer	(A)	$31,151
Target residual cost recovered from a small business customer	(B)	$993
Estimated average number of small business customers in an embedded network[44]	(C)	37
Target residual cost recovered from small business customers in embedded network.	(D) *(B) * (C)*	$36,894
Shortfall in residual cost recovery from an embedded network	(E) *(A) – (D)*	-$5,743
Potential opex saving from embedded network formation	(F)	$1,224

[44] The average number of small business customers in an embedded network is estimated by dividing the annual average embedded network consumption by the annual average small business customer consumption.

Net cost to customers of embedded network formation	(G) *(E) + (F)*	-$4,519
Average annual embedded network billed demand		1,990 kW
Embedded network price added to large LV demand tariff		7.5 c/kW/day

We expect that assigning our LV embedded network customers to the Embedded Network tariff will have an average impact on customers network bills of 9%, which represents the unwinding of a historical inequity while recognising the potential for incremental opex savings[45]. Figure 37 illustrates the expected distribution of bill impacts across impacted embedded network customers.

Figure 37: Impact of proposed embedded network tariff on impacted customers



To mitigate the adjustment impact on our impacted embedded network customers, we propose to transition to the full Embedded Network tariff over a two-year period.

5.6 Tariff trials

Endeavour Energy will continue to use tariff trials to develop new tariffs over the course of the 2024-29 regulatory control period. Planned tariff trials include:

- Dynamic scheduled load tariffs designed to facilitate solar soaking and peak demand management using hot water and EV charging loads.
- Subject to appropriate customer connection to our network, we would like to explore options to add dynamic pricing components to our proposed HV grid connected battery tariffs.

[45] In our January 2023 TSS submission the expected average impact of the proposed embedded network tariff was 12%.

Impact of proposed tariffs on our customers

Chapter 6

6.1 Residential tariffs

6.1.1 Charging windows and tariff structures

Our analysis in section 5.3 indicates that demand is highly sensitive to temperature and typically occurs later in the day. This is reflected in the seasonal component of our cost reflective residential tariffs with the on-peak period applying from 4pm to 8pm on business days.

This indicates that there are no necessary changes to the charging windows for existing import charges.

However, with the inclusion of export charges for some residential customers there are two necessary periods to define the:

- period when an export reward will be offered – which is the existing peak import period; and
- period when an export charge will be applied – which is the 'solar soak' period.

The export reward during the peak import period will be of the same structure as the import charge that applies at that time. It will also be equal in magnitude to the long-run marginal cost of the charge, but in the opposite direction, reflecting the symmetry of flows and prices.

Our analysis in section 5.3 indicates that export customers are a major contributor to the low demand in the middle of the day. The solar soak period is defined as 10am-2pm for residential customers on all days. During the solar soak period, a relative discount will be offered on the energy charge that applies during this time.

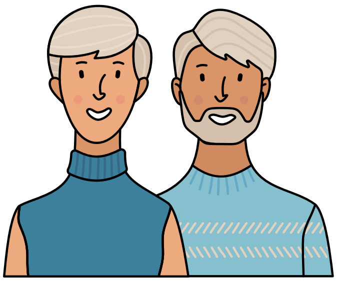
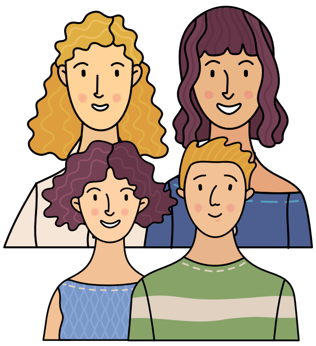
6.1.2 Customer assignment to cost-reflective tariff options

Over the course of the 2024-29 regulatory control period we anticipate:

- 107,000 new residential connections are expected to be added to the network in the 2024-29 regulatory control period, all of which will be assigned to the residential seasonal TOU tariff.
- 686,000 customers to be re-assigned from the residential anytime tariff to a residential seasonal TOU tariff;
- The proportion of interval metered customers on cost-reflective tariff options to increase from 22% in FY22 to 93% by FY29.

6.1.3 How cost reflective tariffs impact different customer types

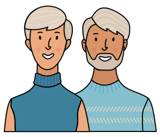
The following personas were developed to aid our Customer Panel consultations. The impact of our proposed cost-reflective Seasonal TOU tariff on different customer types is summarised below. We also estimate the potential for customers to reduce their network bill by changing their consumption profiles in response to the incentives of our cost-reflective tariffs.

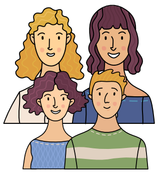
Meet	Their Story
 **Lynette and Ian…**	Lynette and Ian are loving their relaxed lifestyle since they retired to Shellharbour about five years ago. This enabled them to downsize their home to free up some money, but as aged pensioners they are always looking at ways to reduce their cost of living. Because they live in a villa in such a mild coastal climate, their energy usage is lower than most other households at 1,500kWh/year. They are interested in what else they can do to keep their energy costs low and stable to make the most of their fixed budget
 **the Hanlons…**	The two things that matter most to Josh Hanlon are his family and the environment. Living in the Blue Mountains with his partner Mel and their baby Willow, Josh tries to reduce their impact on the natural environment as much as possible. They already have roof-top solar and a home battery, and their next car will be an electric one. This means they don't use as much electricity from the grid as most households (2,000kWh/year). In fact, they export 15,000 kWh/year back to the grid for others to use.
 **the Williams….**	The Williams are a family of four (and their dog) who live in a new home in Cranebrook. They carefully planned their home when it was built to ensure it was energy-efficient, and installed rooftop solar just after they moved in. They try to make the most of their solar investment by using energy-heavy appliances during the day while the sun is shining, actively reducing their energy consumption from the grid. That means they are using about half as much electricity as the average household at 3,000kWh/year and export about the same amount back to the grid each year. They are planning to install a home battery next year to further reduce their bills and take control of their energy costs
 **the Patels…**	As working parents with young children, Raj and Nita Patel never have enough time in the day. Rushing to and from work, childcare and school during the week, and taking the kids to various sports on weekends, the Patels are the typical Endeavour Energy customer household. Their 1980s home is not as energy efficient as it could be, so they find themselves using about 6,000 kWh/year. They want to reduce their bills so are looking at installing rooftop solar next year to reduce their consumption of energy from the grid by during the day.

Meet	Their Story
 **Downtown Dry Cleaning…**	Albert and the team at Downtown Dry Cleaning pride themselves on great customer service. Owned and operated by Albert's family since they arrived in Australia in 1975, this small business survived the pandemic shutdowns and is now back open during business hours Monday to Friday to cater for the growing number of professionals working from the heart of Parramatta. Downtown Dry Cleaning uses about 9,000kWh/year of electricity, the average for small businesses in Endeavour Energy's area. Kevin is looking to reduce bills and thinks that he should be able to make savings as he is not operating during the evening peak demand period on the network.
 **the Jamberoo farmer…**	Sustainable farming is a way of life for Jodie Taylor and her family. As an established small-scale producer of free-range eggs, she lives and works on their 5-acre property in the beautiful Jamberoo Valley. They rely on electricity for both their business and family life, and although they have installed roof top solar they are still heavily dependent on the grid for their energy needs, using about 14,000kWh/year and exporting 2,500 kWh/year Jodie is looking to save money by accessing tariffs that reward usage outside peak periods, as well as looking into additional solar and storage options.

The table below illustrates how these customers can take control of their network bills through the choices they make, by presenting the estimated effect of various decisions on annual network bills.

Table 12: Impact of cost-reflective pricing on different customer types

Persona	Move from Anytime to Seasonal TOU Energy tariff	Shift import from peak to soak period	Opt-in to two-way pricing	Shift export from soak to peak period	Potential Bill Saving
 **Lynette and Ian** Pensioners from Shellharbour **1,600kWh/year** Without Solar	**-$8** ▼	**-$4** ▼	**-**	**-**	**-$12** ▼

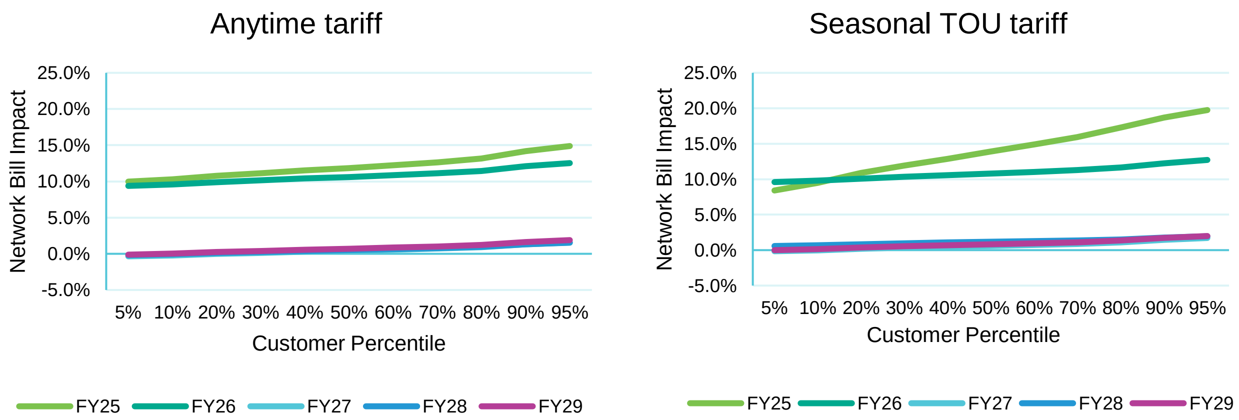
Persona	Move from Anytime to Seasonal TOU Energy tariff	Shift import from peak to soak period	Opt-in to two-way pricing	Shift export from soak to peak period	Potential Bill Saving
 **The Hanlons** Renewable energy family from the Blue Mountains **1,800kWh/year** With Solar	**$13** ▲	**-$6** ▼	**$104** ▲	**-$212** ▼	**-$101** ▼
 **The Williams** Family of four from Cranebrook **4,800 kWh/year** With Solar	**$7** ▲	**-$13** ▼	**-$3** ▼	**-$67** ▼	**-$76** ▼
 **The Patels** Young family from Seven Hills **6.000kWh/year** Without Solar	**-$21** ▼	**-$14** ▼	**-**	**-**	**-$35** ▼
 **Downtown Dry Cleaning** Dry cleaner from Parramatta **13,100 kWh/year** Without Solar	**-$356** ▼	**-$3** ▼	**-**	**-**	**-$359** ▼

Persona	Move from Anytime to Seasonal TOU Energy tariff	Shift import from peak to soak period	Opt-in to two-way pricing	Shift export from soak to peak period	Potential Bill Saving
 **Jamberoo farmer** Producer from Jamberoo **13,500 kWh/year** With Solar	**-$21**	**-$28**	**$4**	**-$53**	**-$98**

6.1.4 Detailed bill impact analysis

The figure below illustrates the expected network bill impacts for residential customers on the Anytime tariff and Seasonal TOU tariff. Annual bill impacts include estimated CPI of 2.8% and are set using our smoothed annual revenue requirement as proposed in our revised Regulatory Proposal. Estimated transmission costs and jurisdictional scheme amounts, including an estimate of future NSW Electricity Infrastructure Roadmap contributions, are included in this analysis.

Figure 38: Indicative annual network bill impact for residential Anytime and Seasonal TOU tariffs



Under our proposed residential tariff assignment policy, existing customers with an interval meter and at least 12-months of interval meter data will be reassigned from the Anytime tariff to the Seasonal TOU tariff.

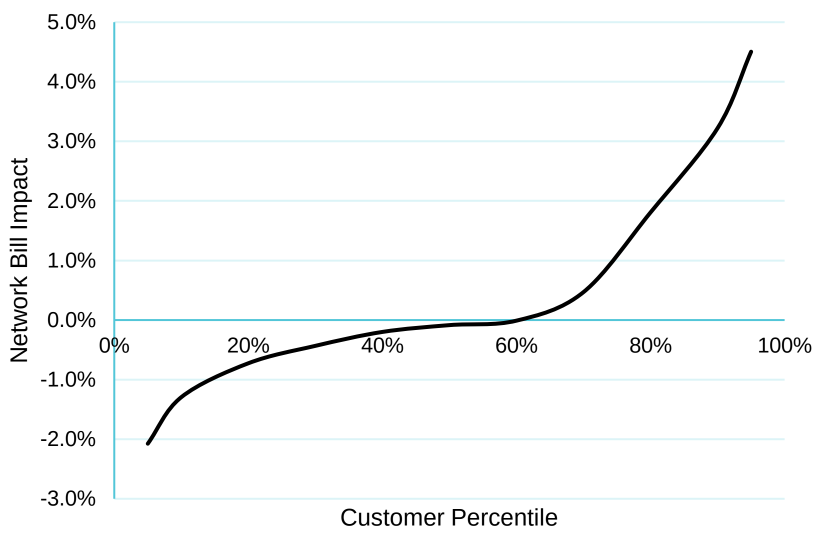
The network bill impact of a reassignment of a non-solar and solar residential customer from the Anytime tariff to the Seasonal TOU tariff is illustrated in the figure below.

Figure 39: Impact of reassignment from Anytime to Seasonal TOU tariff

From 1 July 2025, we will assign all new solar customers to the two-way tariff. Customers assigned to the tariff will retain the right to opt-out of this tariff.

The network bill impact of assignment to the two-way tariff is illustrated in the figure below.

Figure 40: Impact of assignment to the two-way tariff



6.2 General supply tariffs

6.2.1 Charging windows and tariff structures

Our general supply tariffs have the same charging windows and tariff structures as our residential tariffs:

- a seasonal on-peak period applying from 4pm to 8pm on business days; and
- a solar soak period is defined as 10am-2pm on all days

6.2.2 Customer assignment to cost-reflective tariff options

Over the course of the 2024-29 regulatory control period we anticipate:

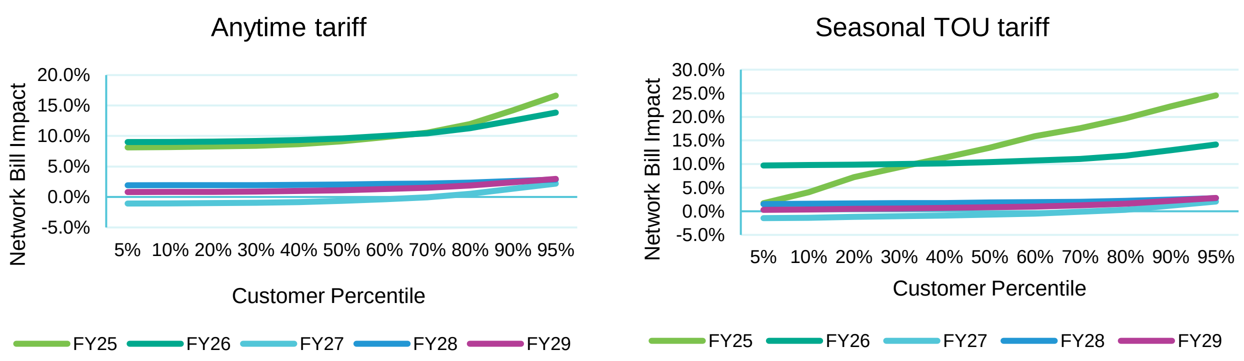
- 11,000 new general supply connections are expected to be added to the network in the 2024-29 regulatory control period, all of which will be assigned to the general supply seasonal TOU tariff.

- 53,000 customers to be re-assigned from the general supply anytime tariff to a general supply seasonal TOU tariff;
- The proportion of interval metered customers on cost-reflective tariff options to increase from 34% in FY22 to 92% by FY29.

6.2.3 Detailed bill impact analysis

The figure below illustrates the expected network bill impacts for general supply customers on the Anytime tariff and Seasonal TOU tariff. Annual bill impacts include estimated CPI of 2.8% and are set using our smoothed annual revenue requirement as proposed in our Regulatory Proposal. Estimated transmission costs and jurisdictional scheme amounts, including an estimate of future NSW Electricity Infrastructure Roadmap contributions, are included in this analysis.

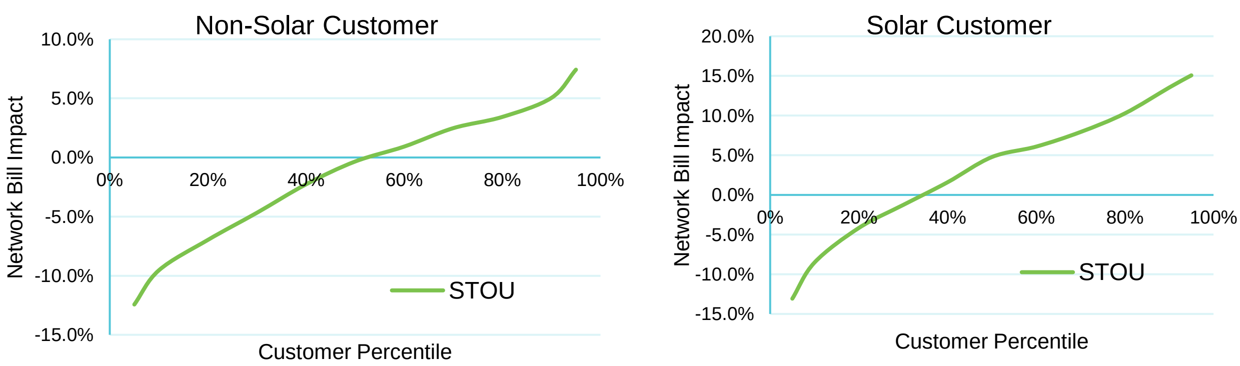
Figure 41: Indicative annual network bill impact for general supply Anytime and Seasonal TOU tariffs



Under our proposed general supply tariff assignment policy, existing customers with an interval meter and at least 12-months of interval meter data will be reassigned from the Anytime tariff to the Seasonal TOU tariff.

The network bill impact of a reassignment of a general supply customer from the Anytime tariff to the Seasonal TOU and transitional Seasonal TOU tariff is illustrated in the figure below.

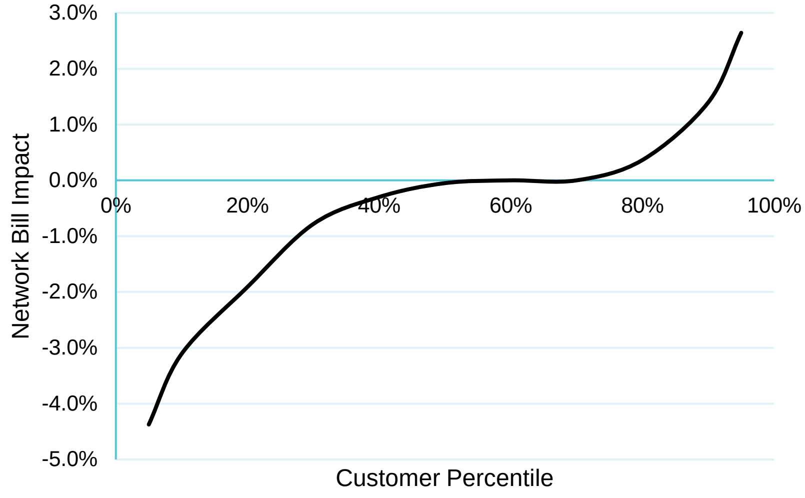
Figure 42: Impact of reassignment from Anytime to Seasonal TOU tariff



From 1 July 2025, we will assign all new solar customers to the two-way tariff. Customers assigned to the tariff will retain the right to opt-out of this tariff.

The network bill impact of assignment to the two-way tariff is illustrated in the figure below.

Figure 43: Impact of assignment to the two-way tariff



6.3 Large Low Voltage, High Voltage and Subtransmission demand tariffs

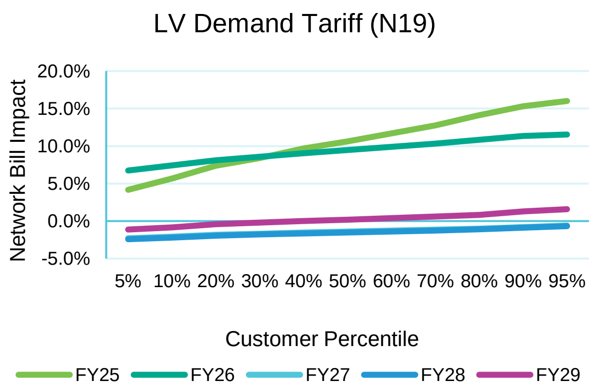
6.3.1 Charging windows and tariff structures

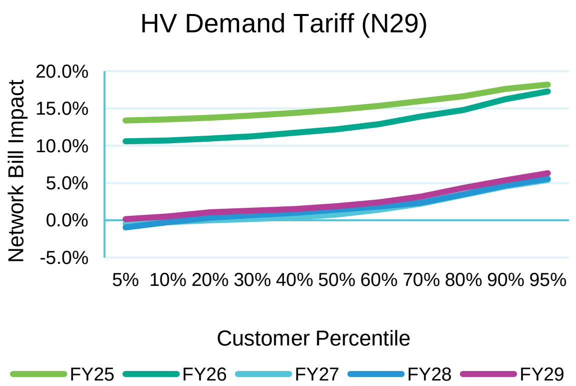
The charging windows and tariff structures for our large low voltage (N19), high voltage (N29) and subtransmission (N39) demand tariffs remain unchanged.

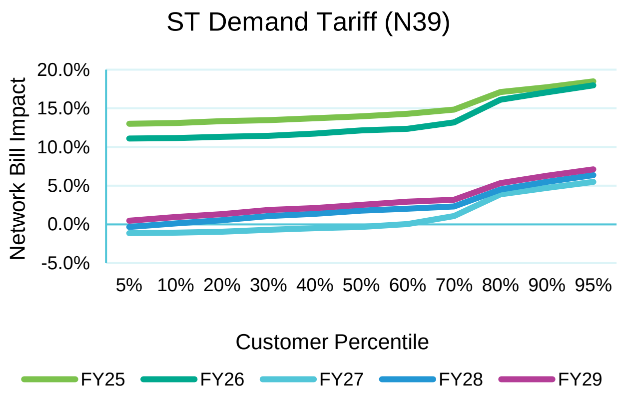
6.3.2 Detailed bill impact analysis

The figure below illustrates the expected network bill impacts for customers on tariffs N19, N29 and N39. Annual bill impacts include estimated CPI of 2.8% and are set using our smoothed annual revenue requirement as proposed in our Regulatory Proposal. Estimated transmission costs and jurisdictional scheme amounts, including an estimate of future NSW Electricity Infrastructure Roadmap contributions, are included in this analysis.

Figure 44: Indicative annual network bill impact for large low voltage, high voltage and subtransmission customers on tariff N19, N29 and N39






ST Demand Tariff (N39)
Network Bill Impact
20.0%
15.0%
10.0%
5.0%
0.0%
-5.0%
5%
10%
20%
30%
40%
50%
60%
70%
80%
90%
95%
Customer Percentile
FY25
FY26
FY27
FY28
FY29

Compliance with Pricing Principles

Chapter 7

The network pricing objective in clause 6.18.5(a) of the Rules requires tariffs to recover the efficient costs of providing the services to customers using these tariffs. The AER determines total efficient costs for Endeavour Energy each year.

In this section, we show compliance with the pricing principles, which are stated in clauses 6.18.5(e)-(j) of the Rules.

7.1 Overview of pricing methodology

Endeavour Energy sets price levels in two steps. First, costs are allocated to individual tariffs and, second, the structure of charges within each individual tariff is determined.

7.1.1 Cost allocation

Endeavour Energy's costs can be characterised into one of two categories, namely:

- the cost of building and maintaining the network; and
- the forward-looking costs associated with providing new services, handling growth in demand and exports and replacing certain parts of the network at the end of their economic life.

The forward-looking costs represent only a small portion of our total costs with building and maintain costs forming the vast majority of our costs. We allocate costs to individual tariffs by ensuring that the forward-looking costs are recovered at a minimum and then the allocate the costs associated with building and maintaining the network, commonly referred to as the 'residual' costs on a basis that minimises changes relative to the previous year. Importantly, Endeavour Energy will not recover residual costs from export charges.

Specifically, we allocate costs to individual tariffs by:

- allocating every tariff the LRMC of the distribution network, consistent with clause 6.18.5(f) of the Rules, by:
    - multiplying import LRMC by the appropriate volume of imports for the collection of all customers on the individual tariff to determine the forward-looking import costs for this tariff; and
    - multiplying export LRMC by the appropriate volume of exports for the collection of all customers on the individual tariff to determine the forward-looking export costs for this tariff; then
- allocating the residual costs to each tariff by taking into account the previous years' allocation of residual costs and a targeted residual cost allocation where costs are allocated based on:
    - shared network asset costs for individually calculated, site specific tariffs; and
    - diversified contribution to peak period demand for 'postage stamp' tariffs.

In our opinion, this approach appropriately takes into consideration the impact on retail customers of changes in tariffs from the previous regulatory year consistent with clause 6.18.5(h) of the Rules.

7.1.2 Tariff structures

The costs allocated to each tariff are then converted to a charging structure, which may include a fixed charge and variable charges for imports and exports, such as consumption and demand charges.

For Seasonal TOU Energy and Seasonal TOU Demand tariffs, we propose to signal to customers the LRMC, both for imports and exports, of providing network services at times of greatest utilisation using the demand charging parameter in Seasonal TOU Demand tariffs and the peak energy charge in Seasonal TOU Energy tariffs. In the context of two-way tariffs, there are now two peak periods which have different time definitions, i.e.:

- the import peak period – which is the traditional evening peak period of high imports; and

- the export peak, or solar soak, period – which is the emerging low demand period in the middle of the day associated with higher output from solar PV systems.

Costs not recovered from import and export LRMC-based charges are recovered from fixed charges, energy charges and demand-based charges. In the absence of reliable information on the price elasticity of demand, this allocation is guided by a rebalancing of the recovery of costs towards fixed charges and away from distortionary consumption-based charges, subject to the extent this rebalancing can be achieved without unacceptable network bill impacts for our customers.

The extent to which we can move towards LRMC-based charging and higher fixed charges is constrained by prioritising the management of customer bill impacts.

7.2 Long run marginal cost

Variations in LRMC can be caused by:

- different times of day, days of the week or months of the year;
- the location in the network; and
- whether the change in use is an increase or a decrease.

The Rules indicate that LRMC should be calculated by reference to the 'times of greatest utilisation'[46] and hence should apply at times corresponding to these periods. For imports, this period is the traditional import peak period which occurs in the early evening. For exports, this period is the period defined by the emerging issues of low load and voltages caused by increased distributor generated solar PV during the middle of the day. This period is referred to as the export peak period or the solar soak period.

Efficient network pricing requires a clear and causal link between customer use of network and the costs that this use imposes on the network. Pricing for two-way flows gives rise to a necessary symmetry between the price signals applying to customer behaviour that either imposes or avoids these network costs, signalled by charges and rewards respectively.

Incorporating both import and export price signals into our tariffs requires an estimation of the forward-looking efficient costs, or LRMC, for both imports and exports. We explain how we determine the months, days and times of day that these LRMC-based prices apply in section 5.3.

7.2.1 Calculating long run marginal cost estimates

There are two main approaches to practically estimating the LRMC, i.e.:

- the perturbation or 'Turvey' approach; and
- the average incremental cost (AIC) approach.

The perturbation approach involves estimating LRMC equal to the change in forward looking operating and capital costs resulting from a small upward or downward perturbation, or change, in forecast demand. Although the perturbation approach best reflects the theoretical construction of LRMC, its application is administratively burdensome, as compared with the AIC approach, and so DNSPs have to date generally favoured the AIC approach.

We do not propose a change in LRMC methodology for this regulatory control period and intend to apply the AIC approach for the calculation of both input and export LRMC.

[46] The Rules, clause 6.18.5(f)(2).

The AIC approach involves estimating LRMC equal to the average change in forward-looking costs resulting from the forecast change in:

- demand - in the case of import LRMC; or
- exports - in the case of export LRMC

over a defined period. It is typically applied by:

- forecasting the level of expected growth in network use over a defined period;
- forecasting the future capital and operating expenditure required to meet that growth; and
- dividing the present value of forecast expenditure by the present value of forecast growth in network use.

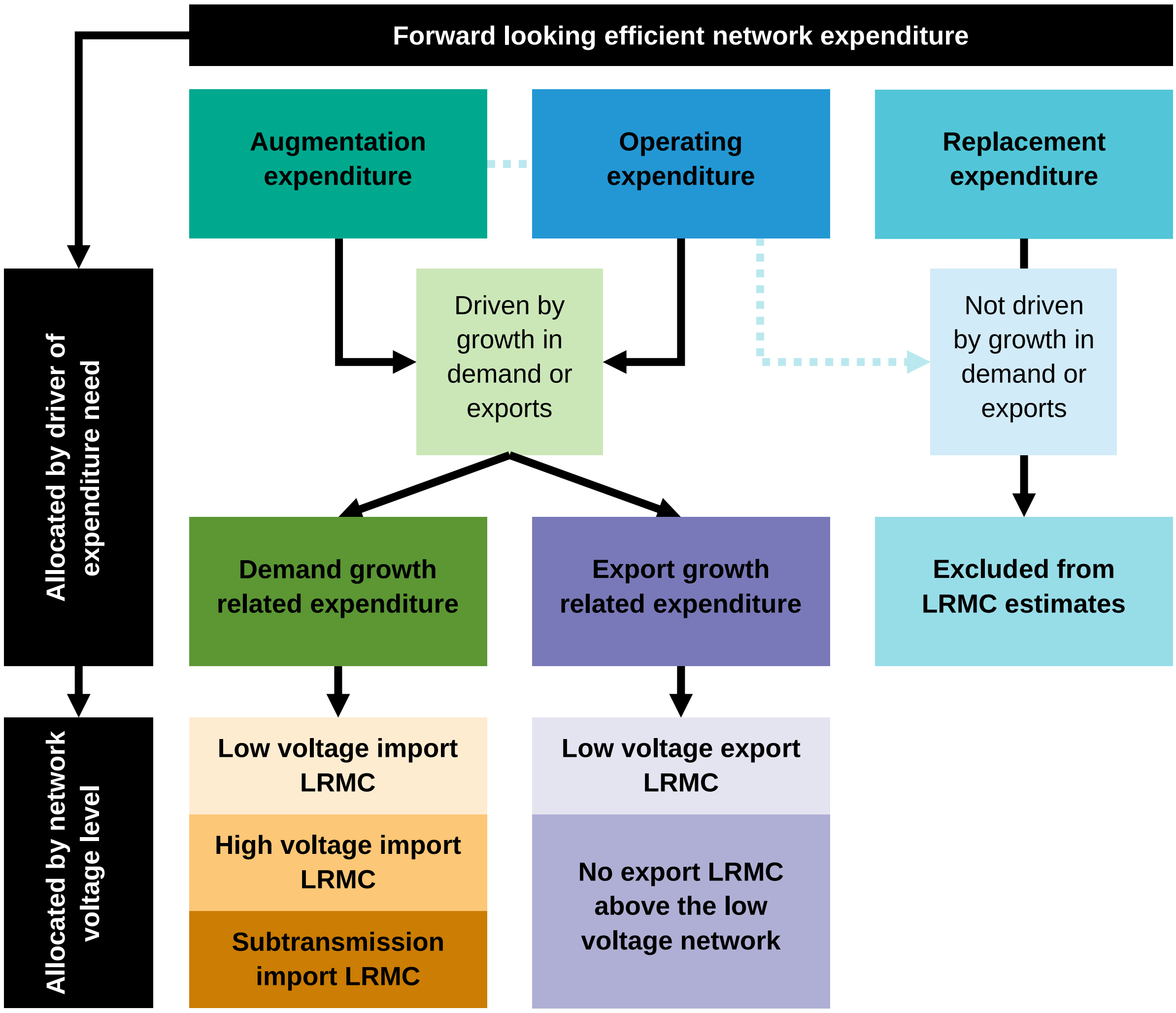
Put differently, the AIC approach involves estimating LRMC as follows, i.e.:

$$LRMC = \frac{NPV(growth\ related\ capital\ and\ operating\ costs)}{NPV(additional\ network\ use\ served)}$$

Given the interrelated nature of imports and exports, and the costs that occasion, we paid careful attention to identifying the primary driver of all future network expenditure, thereby avoiding the risk of duplication and upwards bias in our estimates of import and export LRMC.

We illustrate how we allocated future network expenditure to import LRMC or export LRMC (or neither) below.

Figure 45: Allocation of network expenditure to either import or export LRMC



Our estimates of LRMC include only those components of forward-looking network expenditure that could be avoided through a change in a customer's behaviour. Consistent with the approach that was approved in our previous TSS, our estimates do not include replacement expenditure, since previous analysis indicated that demand growth is not a primary driver of replacement expenditure.

To improve the nexus between the (growth-related) capex and demand inputs to our estimate of import LRMC, we evaluated incremental demand in those areas of the network where demand is growing only.

We are required to offer a basic export level without charge, whereby a retail customer can export to our network up to this level at no additional charge.[47] Alongside export LRMC, the basic export level is an important component to our proposed two-way tariffs.

Our estimates of LRMC and our proposed basic export level are provided in the table below.

[47] AEMC, *Access, pricing and incentive arrangements for distributed energy resources | Final determination,* 12 August 2021, p 68.

Table 13 - LRMC estimates and basic export level by voltage level

Service	Import LRMC estimate ($/kW pa)	Export LRMC estimate ($/kW pa)	Basic Export Level (kWh/customer/annum)
Low Voltage	$81.2	$16.3	1,750 kWh
High Voltage	$9.7	-	-
Subtransmission	$9.5	-	-

7.2.2 Translation of LRMC estimates into charging parameters

The average incremental cost approach yields an LRMC estimate for each network service expressed in dollars per kW per annum. However, many customers are not, and indeed cannot, be charged on the basis of their contribution to the network's maximum demand. It is therefore necessary to express these 'dollars per kW per annum' LRMC estimates (hereafter termed 'base LRMC estimates') in terms of the charging parameters that constitute each tariff.

Translation of LRMC estimates into charging parameters for non-TOU energy tariffs

Translation of LRMC into charging parameters for non-TOU tariffs involves two steps, i.e.:

1. Converting the base LRMC estimate using the power factor for a given customer class.
2. Converting the resulting estimate to dollars per kWh by dividing by the number of hours in the year that the variable tariff component can be charged, i.e.:

$$\text{LRMC estimate (\$ per kWh)} = \frac{\text{LRMC (\$ per kW per year)}}{\text{Hours per year}}$$

Translation of LRMC into charging parameters for TOU energy tariffs

Translation of LRMC into charging parameters for TOU tariffs involves two steps, i.e.:

1. Converting the base LRMC estimate using the power factor for a given customer class.
2. Converting the resulting estimate to dollars per kWh by dividing by the number of hours in the year that the variable tariff component can be charged, i.e.:

$$Peak\ energy\ price\ high\ season = \frac{LRMC \times P(MD) \times (1-\beta^h) \times (1-\alpha)}{number\ of\ high\ season\ peak\ hours}$$

$$Peak\ energy\ price\ low\ season = \frac{LRMC \times P(MD) \times (1-\beta^l) \times (1-\alpha)}{number\ of\ low\ season\ peak\ hours}$$

Where:

$P(MD)$ is the probability of maximum demand occurring in the peak period;

$(1-\beta^h)$ is the per cent allocated to the high-season, and sums to one when added to $(1-\ \beta^l)$;

$(1-\beta^{l})$ is the per cent allocated to the low-season; and

α applies only to large business customers and is the per cent of LRMC recovered from the demand charge, as compared with the peak energy charge, and ensures the *combined* peak energy and demand price signal is appropriately reflects estimated LRMC.

Translation of LRMC into charging parameters for demand tariffs

We have reconsidered the translation of LRMC to demand based charging parameters in our revised proposal. The key changes are:

- The introduction of a diversity factor to ensure the price signal reflects diversity in the timing of each customer's peak demand and their behavioural contribution to maximum demand; and
- The introduction of an allocation factor (β) to better guide the calculation of required difference between high and low season tariffs reflective of differences in seasonal demand.

Translation of LRMC into charging parameters for demand tariffs involves two steps, i.e.:

1. Converting the base LRMC estimate using the power factor for a given customer class (if required).
2. Converting the resulting estimate to dollars per kW or kVA by dividing by the number of months in the year that the variable tariff component can be charged, i.e.:

$$Demand\ price\ high\ season = \frac{LRMC\ \times DF \times P(MD) \times (1-\beta^{h}) \times \alpha}{Number\ of\ high\ season\ months}$$

$$Demand\ price\ low\ season = \frac{LRMC\ \times DF \times P(MD) \times (1-\beta^{l}) \times \alpha}{Number\ of\ low\ season\ months}$$

Where:

DF is the per cent diversity factor for the applicable tariff, and ensures the price signal reflects diversity in the timing of each customer's peak demand and their behavioural contribution to maximum demand;

$P(MD)$ is the probability of maximum demand occurring in the peak period;

$(1-\beta^{h})$ is the per cent allocated to the high-season, and sums to one when added to $(1-\beta^{l})$;

$(1-\beta^{l})$ is the per cent allocated to the low-season; and

α applies only to large business customers and is the per cent of LRMC recovered from the demand charge, as compared with the peak energy charge, and ensures the *combined* peak energy and demand price signal is appropriate.

7.2.3 Treatment of controlled load

Many of Endeavour Energy's low voltage customers purchase a controlled load service in addition to their standard low voltage service. Endeavour Energy has the capability of interrupting a controlled load during system peak events, and so limiting their contribution to the key driver of LRMC. For this reason, the controlled load service will have a much lower LRMC than its non-controlled equivalent.

Endeavour Energy has two different controlled load services, namely:

- the controlled load 1 service, supplied under the N50 tariff; and
- the controlled load 2 service, supplied under the N54 tariff.

To account for the differing obligations on the network arising from these services, we note that:

- the controlled load 1 service is almost entirely interruptible; and
- the controlled load 2 service is largely interruptible, but can nevertheless contribute to a maximum demand event.

Consistent with these observations, Endeavour Energy has assumed that the controlled load 1 service has an LRMC of zero, and the controlled load 2 service has an LRMC equal to 5 per cent of the non-controlled low voltage service.

7.2.4 Compliance with the LRMC criteria

A necessary condition of efficient tariffs is that the variable components of each tariff must be no less than the LRMC of the service so as to not promote inefficient use of the network.

Based on our estimates of LRMC and our proposed translation of these estimates into tariff components, Endeavour Energy believes that our tariffs are compliant with the LRMC criteria of the Rules.

7.3 Stand-alone and avoidable costs

Endeavour Energy sets its tariffs at a level such that, for each tariff class, the revenue we expect to recover from customers lies between:

- the stand alone cost of serving those customers who belong to that tariff class (the upper bound); and
- the avoidable cost of not serving those customers.

The stand-alone cost of serving a group of customers is the total cost required to serve those customers alone, i.e., were we to build the network anew, removing all other customers from the network.

The avoidable cost of serving a group of customers is the reduction in cost that could be achieved if those customers were no longer served, i.e., the reduction in cost associated with a reduction in output that was previously provided to that class of customer.

Endeavour Energy calculates stand-alone and avoidable costs by first classifying each of our network cost categories on the basis of the following two dimensions:

- whether costs are direct or indirect; and
- whether costs are scalable or non-scalable.

Avoidable cost for each tariff class is calculated as the sum of all direct costs multiplied by a weight based on asset value, which represents the proportion of direct costs that are attributable to that tariff class.

Stand-alone cost for each tariff class is calculated by taking the avoidable cost for that tariff class and adding to it:

- all non-scalable indirect costs we incur in operating the network; and

- a proportion of our scalable, indirect costs that can be attributed to that tariff class.

7.4 Treatment of residual costs

The Rules allows for a distributor to recover its residual costs,[48] which are included in its expected revenue allowance.

However, it establishes constraints on the recovery of these costs in that:

- the revenue expected to be recovered from each tariff must reflect the total efficient cost[49] of serving the customers assigned to each tariff; and
- the revenue expected to be recovered from each tariff must minimise distortions to the price signals for efficient usage that would result from tariffs that reflect LRMC.

The requirement that a distributor recovers revenues from each tariff in a manner that minimises distortions for efficient use of the network has implications for:

- the manner in which residual costs are recovered from each tariff, i.e., from the different charging parameters that make up each tariff; and
- the manner in which residual costs are recovered from, or allocated to, different tariffs.

Theoretically, it is most efficient for us to recover from our customers the residual costs we incur exclusively from the fixed charge tariff component because these charges are independent of a customer's usage decisions and therefore minimise the distortion to the LRMC-based price signals that promote efficient usage of our network service.

When a customer's usage charges (either in the form of charges for energy or demand) are set equal to LRMC, the marginal cost to the customer is equal to the marginal cost to the network, which promotes efficiency.

In essence, our allocation is guided by three considerations, or principles, i.e.:

- for tariffs where customers have no alternative tariff, or where the structure of alternative tariffs provides the same strength signals for efficient usage, there is no 'hard and fast' rule as to how they should be allocated, so long as the allocation does not violate the customer impact principle;
- for tariffs where a customer can switch to a tariff with a different strength price signal, residual costs should be assigned so as to encourage customers to shift to tariffs that have the most efficient price signal. Put another way, residual costs should be allocated to tariffs so that customers on more efficient tariffs pay a smaller quantum of residual costs; and
- over time charging parameters will need to be rebalanced to ensure that the shifting of customers between tariffs:
  - does not lead to under- or over-recovery of revenue; and
  - does not result in unacceptable bill shock.

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[48] The Rules, clause 6.18.5(g).

[49] We take this to mean the costs necessary to provide the service to each customer, including allocated operating costs and a return on and of the regulated asset base as allocated to the provision of the service to those customers.

7.5 Changes in revenue for each tariff class abides by the side constraint

Under the Rules,[50] the annual movement in revenue recovered from each tariff class is restricted by the side constraint. The result of the side constraint is a relative limitation (two per cent) on the extent to which a DNSP can increase the revenue recovered from a tariff class, over and above any increase that is required to recover its target revenue or, if revenue is not increasing, above CPI.

The side constraint does not apply to all components of network tariffs nor to individual tariffs, it only applies to distribution use of system (DUOS) charges, which recovers distribution costs, and at the tariff class level. To abide by the side constraint, we will ensure that the total annual increase in DUOS recovered from a tariff class does not exceed the total annual increase in DUOS charges required to recover total distribution costs by more than 2 per cent.

Compliance with the side constraint limitation will be demonstrated as part of our Annual Pricing Proposal.

7.6 Pass through of specified costs

7.6.1 Designated Pricing Proposal Charges

Endeavour Energy's designated pricing proposal charges (DPPC) are designed to recover transmission related costs, including TransGrid's transmission use of system (TUOS) charges, avoided transmission payments made to embedded generators, and adjustments to balance Endeavour Energy's transmission overs and unders account. The DPPC tariffs comprise part of the overall Network Tariffs.

The DPPC amount to be passed on to customers for a particular regulatory year must not exceed the estimated transmission related costs including the overs and unders adjustment amount.

The over and under recovery amount is calculated in a way that:

- ensures that Endeavour Energy is able to recover from customers no more and no less than the transmission related costs it incurs; and
- adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the Endeavour Energy determination for the relevant regulatory year.

The key principles of Endeavour Energy's transmission cost recovery (TCR) methodology are:

- total TUOS allocated to network tariffs are aligned with the total estimated transmission charge to be paid by Endeavour Energy, adjusted for any overs and unders account balance;
- transmission charges are allocated to network tariffs in a manner that reflects the cost drivers present in transmission pricing;
- customers on an individually calculated, site specific tariff have transmission charges allocated in a manner that preserves the location and time signals of transmission pricing; and
- network tariffs for smaller customer classes have transmission charges allocated on an energy basis, as location signals cannot be preserved in all cases due to metering limitations.

7.6.2 Jurisdictional Scheme Amounts

Endeavour Energy is required to recover jurisdictional scheme amounts (JSA) for jurisdictional schemes managed by the NSW Government. Each year Endeavour Energy is notified of the amount that it will be required to pay in the next financial year. This contribution amount, adjusted for over or unders, is recovered from customers through the JSA tariffs. The JSA tariffs comprise part of the overall Network Tariffs.

[50] The Rules, clause 6.18.6.

The JSA amounts to be passed on to customers for a particular regulatory year must not exceed the JSA contribution amounts adjusted for over or under recoveries in previous years.

The over and under recovery amount is calculated in a way that:

- ensures that Endeavour Energy is able to recover from customers no more and no less than the JSA costs it incurs; and
- adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the Endeavour Energy determination for the relevant regulatory year.

Effective 1 July 2023, Endeavour Energy will be required to recover JSA amounts for the NSW Energy Infrastructure Roadmap. The size of these amounts is expected to grow over the 2024-29 Regulatory Control Period.

In the absence of contrary NSW Government direction, we propose to calculate a single price per kWh for this JSA that applies equally to all network tariffs. We believe this is consistent with our pricing principles of transparency and fairness and ensures that each unit of energy imported from our network makes the same contribution to the NSW Government's Energy Infrastructure Roadmap, irrespective of the customers supply voltage or tariff.

7.6.3 NSW Hydrogen Strategy

The NSW Government's Hydrogen Strategy[51] is expected to result in the connection of green hydrogen electrolysers in the Illawarra region of our network. The Strategy requires:

- Distribution businesses to provide these green hydrogen producers a 90% reduction of their network charges;
- Electrolysers to be placed in parts of the network where there is spare capacity; and
- The Network or market operator to be able to direct the electrolyser to turn off if required during a peak event.

For each eligible[52] green hydrogen producer, we propose to deliver the concession using an individually calculated, site-specific tariff. The tariff would be calculated using our standard process for the calculation of site-specific tariffs. The concession will then be applied to the underlying DUOS, DPPC (TUOS) and JSA components as required.

Endeavour Energy's tariffs for any future green hydrogen electrolysers will comply with the requirements of the NSW Government's Hydrogen Strategy.

[51] NSW Hydrogen Strategy, Department of Planning, Industry and Environment (October 2021)

[52] Electricity Supply (General) Amendment (Green Hydrogen Limitation) Regulation 2023

Appendix 1 – Glossary

Term	Definition
ACS	Alternative control service
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AIC	Average incremental cost
ASP	Accredited service provider
CCIA NSW	Caravan and Camping Industry Association of NSW
CER	Customer energy resource
CPI	Consumer price index
CVR	Conservation voltage reduction
DNSP	Distribution network service provider
DPPC	Designated pricing proposal charges
DSO	Distribution system operator
EV's	Electric vehicles
EWON	Energy and Water Ombudsman NSW
GWh	Gigawatt hour
HV	High voltage
IBT	Inclining block tariff
IDT	Inter-distributor transfer
JSA	Jurisdictional scheme amounts
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt hour
LRMC	Long run marginal cost

Term	Definition
LV	Low voltage
LVVA	Low voltage visibility and analytics
NEM	National Electricity Market
NER or the Rules	National Electricity Rules
NPV	Net present value
NUOS	Network Use of System
MVA	Megavolt-ampere
MW	Megawatt
MWh	Megawatt hour
RCP	Regulatory control period
RIN	Regulatory information notice
RRG	Regulatory reference group
SAPS	Stand-alone power systems
SCS	Standard control service
SGA	Market small generation aggregators
SME	Small and medium sized enterprises
ST	Subtransmission voltage
TCR	Transmission cost recovery
TOU	Time of use
TUOS	Transmission use of system
TSES	Tariff structure explanatory statement
TSS	Tariff structure statement
VPP	Virtual power plant

Appendix 2 – Allocation of customers to tariff classes

Assignment of existing customers to tariff classes at the commencement of the next regulatory control period

1. Each customer who was a customer of Endeavour Energy immediately prior to 1 July 2024, and who continues to be a customer of Endeavour Energy as at 1 July 2024, will be taken to be “assigned” to the tariff class which Endeavour Energy was charging that customer immediately prior to 1 July 2024.

Assignment of new customers to a tariff class during the next regulatory control period

2. If, after 1 July 2024, Endeavour Energy becomes aware that a person will become a customer of Endeavour Energy, then Endeavour Energy will determine the tariff class to which the new customer will be assigned.

3. In determining the tariff class to which a customer or potential customer will be assigned, or reassigned, in accordance with paragraph 2 or 5, Endeavour Energy will take into account one or more of the following factors:
   a) the nature and extent of the customer’s usage;
   b) the nature of the customer’s connection to the network; and
   c) whether remotely–read interval metering or other similar metering technology has been installed at the customer’s premises as a result of a regulatory obligation or requirement.

4. In addition to the requirements under paragraph 3, Endeavour Energy, when assigning or reassigning a customer to a tariff class, will ensure the following:
   a) that customers with similar connection and usage profiles are treated equally; and
   b) that customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities.

Reassignment of existing customers to another existing or a new tariff during the next regulatory control period

5. If Endeavour Energy believes that an existing customer’s load characteristics or connection characteristics (or both) are no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned or a customer no longer has the same or materially similar load or connection characteristics as other customers on the customer’s existing tariff, then Endeavour Energy may reassign that customer to another tariff class.

Notification of proposed assignments and reassignments

6. Endeavour Energy will notify the customer’s retailer in writing of the tariff class to which the customer has been assigned or reassigned, prior to the assignment or reassignment occurring.

7. A notice under paragraph 6 above must include advice informing the customer’s retailer that they may request further information from Endeavour Energy and that the customer’s retailer may object to the proposed reassignment. This notice must specifically include reference to Endeavour Energy’s published procedures for customer complaints, appeals and resolution.

8. If the objection is not resolved to the satisfaction of the customer's retailer under the Endeavour Energy's internal review system or EWON, then the retail customer is entitled to seek a decision of the AER via the dispute resolution process available under Part 10 of the NEL.

9. If, in response to a notice issued in accordance with paragraph 7 above, Endeavour Energy receives a request for further information from a customer’s retailer, then it must provide such information within a reasonable timeframe. If Endeavour Energy reasonably claims confidentiality over any of the information requested by the customer’s retailer, then it is not required to provide that information to the retailer or retail customer. If the customer’s retailer disagrees with such confidentiality claims, it

may have resort to the dispute resolution procedures referred to in paragraph 7 above (as modified for a confidentiality dispute).

10. If, in response to a notice issued in accordance with paragraph 7 above, a customer’s retailer makes an objection to Endeavour Energy about the proposed assignment or reassignment, Endeavour Energy must reconsider the proposed assignment or reassignment. In doing so Endeavour Energy must take into consideration the factors in paragraphs 3 and 4 above, and notify the customer’s retailer in writing of its decision and the reasons for that decision.

11. If a customer’s retailer objection to a tariff class assignment or reassignment is upheld, in accordance with Endeavour Energy’s published procedures for customer complaints, appeals and resolution then any adjustment which needs to be made to tariffs will be done by Endeavour Energy as part of the next annual review of prices.

System of assessment and review of the basis on which a customer is charged

12. Where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer’s usage or load profile, Endeavour Energy will set out in its pricing proposal a method of how it will review and assess the basis on which a customer is charged.

Appendix 3 – Proposed charging parameters

Our proposed tariff structures for Standard Control Services are set out in the sections below.

1.1 Small low voltage tariff class

The charging parameters for the proposed tariff structures for our small low voltage customers are set in table A3.1 below:

Table A3.1: Charging parameters for the small low voltage tariff class

Tariff type	Components	Units	Charging parameter
Residential Anytime Energy	Fixed	c/day	Daily access charge
	Energy	c/kWh	Charge applied to all energy consumption
General Supply Anytime Block Energy	Fixed	c/day	Daily access charge
	1st Block Energy	c/kWh	Charge applied to energy consumption up to and including 120MWh per annum[53]
	2nd Block Energy	c/kWh	Charge applied to energy consumption above 120MWh per annum
Residential & General Supply Seasonal TOU Energy tariffs	Fixed	c/day	Daily access charge
	High-season peak energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season peak energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Solar soak energy	c/kWh	Charge applied to energy consumed between 10:00 to 14:00 on all days.
	Off-peak energy	c/kWh	Charge applied to energy consumed at all other times
Residential & General Supply Seasonal TOU Demand tariffs	Fixed	c/day	Daily access charge
	Solar soak energy	c/kWh	Charge applied to energy consumed between 10:00 to 14:00 on all days.

[53] Endeavour Energy has displayed block tariff consumption thresholds on a MWh per annum basis. In practice, this annualized consumption threshold will be calculated on a daily basis and applied to the billing period.

Tariff type	Components	Units	Charging parameter
	Energy	c/kWh	Charge applied to energy consumed at all other times
	High-season peak demand	c/kW/day	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season peak demand	c/kW/day	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
Prosumer (import / export)	Export charge	c/kWh	Charge applied to maximum energy export between 10:00 to 14:00 on all days. Applies to energy export greater than 1,750 kWh per annum[54].
	High-season energy export	c/kWh	Reward applied to energy exported between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season energy export	c/kWh	Reward applied to energy exported between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
Low voltage grid connected battery (Import)	Fixed	c/day	Daily access charge
	High-season peak energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season peak energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Solar soak energy	c/kWh	Charge applied to energy consumed between 10:00 to 14:00 on all days.
	Off-peak energy	c/kWh	Charge applied to energy consumed at all other times

[54] Endeavour Energy has displayed basic export level threshold on a kWh per annum basis. In practice, this annualized consumption threshold will be calculated on a daily basis and applied to the billing period.

Tariff type	Components	Units	Charging parameter
Low voltage grid connected battery (Export)	High-season peak energy export	c/kWh	Reward applied to energy exported between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season peak energy export	c/kWh	Reward applied to energy exported between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Export charge	c/kWh	Charge applied to maximum energy export between 10:00 to 14:00 on all days. Applies to energy export greater than 1,750 kWh per annum[55].
	Off-peak energy	c/kWh	Reward applied to energy exported at all other times
Controlled Load 1	Fixed	c/day	Daily access charge
	Energy	c/kWh	Charge applied to controlled energy consumption where energy consumption is controlled by our equipment so that supply may not be available between 07:00 and 22:00.
Controlled Load 2	Fixed	c/day	Daily access charge
	Energy	c/kWh	Charge applied to controlled energy consumption where supply is available for restricted periods not exceeding a total of 17 hours in any period of 24 hours.

[55] Endeavour Energy has displayed basic export level threshold on a kWh per annum basis. In practice, this annualized consumption threshold will be calculated on a daily basis and applied to the billing period.

1.2 Large low voltage tariff class

The charging parameters for the proposed tariff structures for our large low voltage customers are set in the table below:

Table A3.2: Charging parameters for the large low voltage tariff class

Tariff type	Components	Units	Charging parameter
Seasonal TOU Demand	Fixed	c/day	Daily access charge.
	High-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off Peak Energy	c/kWh	Charge applied to all energy consumed at all other times.
	High-season Demand	c/kVA/day	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Demand	c/kVA/day	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
Transitional Seasonal TOU Energy	Fixed	c/day	Daily access charge.
	High-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off Peak Energy	c/kWh	Charge applied to energy consumed at all other times.
Embedded network tariff	As per the Seasonal TOU Demand tariff.		

Tariff type	Components	Units	Charging parameter
Site-specific LV Demand	As per the Seasonal TOU Demand tariff.		

1.3 High voltage tariff class

The charging parameters for the proposed tariff structures for our high voltage customers are set in the table below:

Table A3.3: Charging parameters for the high voltage tariff class

Tariff type	Components	Units	Charging parameter
Seasonal TOU Demand	Fixed	c/day	Daily access charge.
	High-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off Peak Energy	c/kWh	Charge applied to all energy consumed at all other times.
	High-season Demand	c/kVA/day	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Demand	c/kVA/day	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
Site-specific HV Demand	As per the Seasonal TOU Demand tariff.		
Site-specific HV Grid Battery	Fixed	c/day	Daily access charge.
	High-season peak energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.

Tariff type	Components	Units	Charging parameter
	Low-season peak energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off-peak energy	c/kWh	Charge applied to energy consumed at all other times
	High-season peak energy export	c/kWh	Reward applied to energy exported between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season peak energy export	c/kWh	Reward applied to energy exported between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off-peak energy	c/kWh	Reward applied to energy exported at all other times.

1.4 Subtransmission voltage tariff class

The charging parameters for the proposed tariff structures for our subtransmission voltage customers are set in the table below:

Table A3.4: Charging parameters for the subtransmission voltage tariff class

Tariff type	Components	Units	Charging parameter
Seasonal TOU Demand	Fixed	c/day	Daily access charge.
	High-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off Peak Energy	c/kWh	Charge applied to all energy consumed at all other times.
	High-season Demand	c/kVA/day	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.

Tariff type	Components	Units	Charging parameter
	Low-season Demand	c/kVA/day	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
Site-specific ST Demand	As per the Seasonal TOU Demand tariff.		
Site-specific ST Grid Battery	Fixed	c/day	Daily access charge.
	High-season peak energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season peak energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off-peak energy	c/kWh	Charge applied to energy consumed at all other times
	High-season peak energy export	c/kWh	Reward applied to energy exported between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season peak energy export	c/kWh	Reward applied to energy exported between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off-peak energy	c/kWh	Reward applied to energy exported at all other times

1.5 Inter-distributor transfer tariff class

The charging parameters for the proposed tariff structures for our inter-distributor tariff (IDT) customers are set in the table below:

Table A3.5: Charging parameters for the inter-distributor transfer tariff class

Tariff type	Components	Units	Charging parameter
IDT	Fixed	c/day	Daily access charge.
	High-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days.

Tariff type	Components	Units	Charging parameter
			High-season includes the months November to March inclusive.
	Low-season Peak Energy	c/kWh	Charge applied to energy consumed between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.
	Off Peak Energy	c/kWh	Charge applied to all energy consumed at all other times.
	High-season Demand	c/kW/day	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. High-season includes the months November to March inclusive.
	Low-season Demand	c/kW/day	Charge applied to maximum energy demand between 16:00 to 20:00 on business days. Low-season includes the months April to October inclusive.

1.6 Unmetered supply tariff class

The charging parameters for the proposed tariff structures for our inter-distributor tariff customers are set in the table below:

Table A3.6: Charging parameters for the unmetered supply tariff class

Tariff type	Components	Units	Charging parameter
Unmetered energy tariff	Energy	c/kWh	Charge applied to all energy consumption.

Appendix 4 – Compliance checklist

This section sets out the TSS Rule requirements and the section in which those requirements have been met within the TSS.

Rule Provision	Requirement	TSS	TSES
Part E: Regulatory proposal and proposed tariff structure statement			
6.8.2	**Submission of tariff structure statement**		
6.8.2(a)	A *Distribution Network Service Provider* must, whenever required to do so under paragraph (b), submit to the *AER* a *regulatory proposal* and a proposed *tariff structure statement* related to the *distribution services* provided by means of, or in connection with, the *Distribution Network Service Provider's distribution system*.	Noted	Noted
6.8.2(b)	A *regulatory proposal*, a proposed *tariff structure statement* and, if required under paragraph (a1), an *exemption application* must be submitted: (1) at least 17 months before the expiry of a distribution determination that applies to the *Distribution Network Service Provider*; or (2) if no distribution determination applies to the *Distribution Network Service Provider*, within 3 months after being required to do so by the *AER*.	Noted	Noted
6.8.2(d1)	The proposed *tariff structure statement* must be accompanied by an *indicative pricing schedule*.	Appendix 1 & Appendix 2	
6.8.2(d2)	The proposed *tariff structure statement* must comply with the *pricing principles for direct control services.*	Chapter 3	Chapter 7
Part I: Distribution Pricing Rules			
6.18.1A	**Tariff Structure Statement**		
6.18.1A(a)(1)	The *tariff structure statement* must include the *tariff classes* into which *retail customers* for *direct control services* will be divided during the relevant *regulatory control period*.	Section 2.1	Section 5.2
6.18.1A(a)(2)	The *tariff structure statement* must include the policies and procedures the *Distribution Network Service Provider* will apply for assigning *retail customers* to tariffs or reassigning *retail customers* from one tariff to another (including any applicable restrictions).	Section 2.2 Chapter 5	Appendix 2

Rule Provision	Requirement	TSS	TSES
6.18.1A(a)(2A)	The *tariff structure statement* must include a description of the strategy or strategies the *Distribution Network Service Provider* has adopted, taking into account the pricing principle in clause 6.18.5(h), for the introduction of *export tariffs* including where relevant the period of transition (*export tariff transition strategy*);	Chapter 6	Sections 5.3.5 to 5.3.8
6.18.1A(a)(3)	The *tariff structure statement* must include the structures for each proposed tariff.	Chapter 4	Appendix 3
6.18.1A(a)(4)	The *tariff structure statement* must include the *charging parameters* for each proposed tariff.	Chapter 4	Appendix 3
6.18.1A(a)(5)	The *tariff structure statement* must include a description of the approach that the *Distribution Network Service Provider* will take in setting each tariff in each *pricing proposal* during the relevant *regulatory control period* in accordance with clause 6.18.5 (pricing principles). Note Under clause 11.141.13(a), a *tariff structure statement* of a *Distribution Network Service Provider* applicable during the tariff transition period for the *Distribution Network Service Provider* must also include, for each proposed *export tariff*, the basic export level or the manner in which the basic export level will be determined and the eligibility conditions applicable to each proposed *export tariff*.	Chapters 3, 5 & 6	Section 5.3.6
6.18.1A(b)	The *tariff structure statement* must comply with the *pricing principles for direct control services*.	Chapter 3	Chapter 7
6.18.1A(e)	A *tariff structure statement* must be accompanied by an *indicative pricing schedule* which sets out, for each tariff for each *regulatory year* of the *regulatory control period*, the indicative price levels determined in accordance with the *tariff structure statement.*	Appendix 1 & Appendix 2	
6.18.3	**Tariff Classes**		
6.18.3(b)	Each customer for *direct control services* must be a member of 1 or more *tariff classes*.	Sections 2.1 & 2.2	Section 5.2 Appendix 2

Rule Provision	Requirement	TSS	TSES
6.18.3(c)	Separate *tariff classes* must be constituted for *retail customers* to whom *standard control services* are supplied and *retail customers* to whom *alternative control services* are supplied (but a customer for both *standard control services* and *alternative control services* may be a member of 2 or more *tariff classes*).	Sections 2.1 & 2.2	Section 5.2 Appendix 2
6.18.3(d)	A *tariff class* must be constituted with regard to: 1. the need to group *retail customers* together on an economically efficient basis; and 2. the need to avoid unnecessary transaction costs.	Section 2.1	Section 5.2
6.18.4	**Principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of basis of charging**		
6.18.4(a)	In formulating provisions of a distribution determination governing the assignment of *retail customers* to *tariff classes* or the re-assignment of *retail customers* from one *tariff class* to another, the AER must have regard to the following principles:	Noted	Noted
6.18.4(a)(1)	*retail customers* should be assigned to *tariff classes* on the basis of one or more of the following factors: • the nature and extent of their usage; • the nature of their connection to the network; • whether remotely-read interval metering or other similar metering technology has been installed at the retail customer's premises as a result of a regulatory obligation or requirement;	Sections 2.1 & 2.2	Section 5.2 Appendix 2
6.18.4(a)(2)	retail customers with a similar connection and usage profile should be treated on an equal basis, subject to subparagraph (3A);	Sections 2.1 & 2.2	Section 5.2 Appendix 2
6.18.4(a)(3A)	*retail customers connected* to a *regulated SAPS* should be treated no less favourably than *retail customers connected* to the interconnected national electricity system; and	Sections 2.1 & 2.2	Section 5.2 Appendix 2
6.18.4(a)(4)	a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review. Note: If (for example) a customer is assigned (or reassigned) to a tariff class on the basis of the customer's actual or assumed maximum demand, the system of assessment and review should allow for the reassignment of a customer who demonstrates a reduction or increase in maximum demand to a tariff class that is more appropriate to the customer's load profile.	Section 2.2	Appendix 2

Rule Provision	Requirement	TSS	TSES
6.18.4(b)	If the *charging parameters* for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.	Section 2.2	Appendix 2
6.18.5	**Network Pricing Principles**		
6.18.5(a)	The network pricing objective is that the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer. Note: Charges in respect of the provision of direct control services may reflect efficient negative costs.	Chapter 3	Chapter 7
6.18.5(b)	Subject to paragraph (c), a *DNSP's* tariffs must comply with the pricing principles set out in paragraphs (e) to (j).	Chapter 3	Chapter 7
6.18.5(c)	A Distribution Network Service Provider's tariffs may vary from tariffs which would result from complying with the pricing principles set out in paragraphs (e) to (g) only: to the extent permitted under paragraph (h); and to the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).	Chapter 3	Chapter 7
6.18.5(d)	A *Distribution Network Service Provider* must comply with paragraph (b) in a manner that will contribute to the achievement of the *network pricing objective*.	Chapter 3	Chapter 7
6.18.5(e)	For each tariff class, the revenue expected to be recovered must lie on or between: 1. an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and 2. a lower bound representing the avoidable cost of not serving those retail customers.	Chapter 3	Chapter 7

Rule Provision	Requirement	TSS	TSES
6.18.5(f)	Each tariff must be based on the *long run marginal cost* of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to: 1. the costs and benefits associated with calculating, implementing and applying that method as proposed; 2. the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network; and 3. the location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network.	Chapter 3	Chapter 7
6.18.5(g)	The revenue expected to be recovered from each tariff must: 1. reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff; 2. when summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider; and comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).	Chapter 3	Chapter 7

Rule Provision	Requirement	TSS	TSES
6.18.5(h)	A Distribution Network Service Provider must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the Distribution Network Service Provider considers reasonably necessary having regard to: • the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period); • the extent to which retail customers can choose the tariff to which they are assigned; and • the extent to which retail customers are able to mitigate the impact of changes in tariffs through their decisions about usage of services.	Chapter 3	Chapter 6
6.18.5(i)	The structure of each tariff must be reasonably capable of: (1) being understood by *retail customers* that are or may be assigned to that tariff (including in relation to how decisions about usage of services or controls may affect the amounts paid by those customers) or (2) being directly or indirectly incorporated by *retailers* or *Market Small Generation Aggregators* in contract terms offered to those customers, having regard to information available to the *Distribution Network Service Provider*, which may include: (3) the type and nature of those *retail customers*; (4) the information provided to, and the consultation undertaken with, those *retail customers*; and (5) the information provided by, and consultation undertaken with, *retailers* and *Market Small Generation Aggregators*.		Chapter 3
6.18.5(j)	A tariff must comply with the *Rules* and all *applicable regulatory instruments*.	Noted	Noted

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