Explanatory Statement

In support of the Revised Regulatory Proposal 2025-30

November 2024

Part of Energy Queensland

Contact details

Manager Network Pricing & Tariffs

PO Box 1090, Townsville QLD 4810
Level 6, 420 Flinders Street, Townsville QLD 4810
www.energyq.com.au

Copyright

© Ergon Energy Corporation Limited (ABN 50 087 646 062) and Energy Queensland Limited (ABN 96 612 535 583)

This material is copyright. No part of this material may be copied, reproduced, adapted or transmitted in any form without the prior written consent of the copyright owner/s, except as permitted under the *Copyright Act* 1968 (Cth). If consent is provided, it will be subject to the requirement that there is due acknowledgement of the copyright owner/s as the source.

Requests and enquiries concerning reproduction and rights for a purpose other than personal, in-house or non-commercial use, should be addressed to the Manager Economic Regulation, Energy Queensland, PO Box 1090, Townsville QLD 4810

Contents

1 OVERVIEW

1.1 Purpose of the Tariff Structure Explanatory Statement

This Tariff Structure Explanatory Statement (Explanatory Statement) provides further information to support our 2025-30 Tariff Structure Compliance Statement (TSS) submission to the Australian Energy Regulator (AER).

Our TSS provides necessary information regarding the tariffs and assignment arrangements that will apply from 1 July 2025 and how they comply with the National Electricity Rules (NER).[1]

Our Explanatory Statement provides additional information on how we arrived at our network tariff structures and charges for the 2025-30 regulatory control period. This includes the outcome of changes that applied in the current period, key influences of further reform and change and how we have incorporated customer preferences and choice into our final designs.

On 23 September 2024, the AER published the Ergon Energy Corporation Limited (Ergon Energy Network) Draft Decision, in which the AER approved the following:

- Tariff structures for residential and small business customers, not including two-way tariffs or the new optional flexible load tariffs.
- Tariff structures for large low voltage (LV) and high voltage (HV) business customers, not including two-way tariffs.
- Tariff assignment for HV business customers.
- Continuation of existing primary and secondary load control tariffs.
- Tariff streamlining and withdrawal of obsolete or closed tariffs.
- Approach to setting and assigning customers to Individually Calculated Customer (ICC) tariffs.

The AER did not accept parts of our Initial TSS and requested the following changes:

- Tariff assignment for residential and small business customers.
- Two-way tariffs (charging mechanisms and explanation of our transition strategy).
- Tariff assignment for large LV business customers.
- Flexible load tariffs.
- Grid-scale storage tariffs.

Our TSS includes changes to tariff structures and assignment arrangements in response to the AER's Draft Decision. In this Explanatory Statement we have provided additional information the AER has requested.

Table 1 provides a summary of our response to the AER's Draft Decision.

[1] Rule 6.8 of the NER.

Issue in draft decision	Changes requested by the AER	Our response
Tariff assignment for residential and small business customers	Change default assignment for residential and small business customers with smart meters from TOU Demand and Energy tariffs to TOU Energy tariffs. Reassign existing customers from current default Transitional Demand tariffs to TOU Energy tariffs.	Assignment arrangements are amended in our Revised TSS in response to the AER's Draft Decision. New and upgrading residential and small business customers will be assigned to TOU Energy tariffs. Retailer led meter upgrades will result in an assignment to TOU Energy tariffs 12 months after the financial year in which the upgrade occurred. The TOU Demand and Energy tariffs will remain as optional tariffs. Time of use Energy tariffs will not be assigned retrospectively to customers on the current default tariff. These customers will remain on their current default tariff but retain the option to access TOU Energy tariffs during the 2025-30 period if they choose.
Contingent tariff adjustments	Include further information on contingent tariff adjustments to remove obsolete tariff within the 2025-30 period.	In response to the AER's Draft Decision and customer feedback we will remove the contingent tariff adjustment from our Revised TSS. Instead, we will withdraw the legacy small business Wide Inclining Fixed tariff from 1 July 2025. We expect this change will increase transparency for basic meter customers and ultimately assist with the transition to a more cost reflective tariff.
Two-way tariffs	Include an explicit export tariff transition strategy. Convert export charges and basic export level from kW to kWh. Include network bill impact analysis for small businesses and large customers to face two-way tariffs.	Our Initial TSS introduced two-way tariffs, commencing for new customers from 1 July 2026 and transitioning to all customers from 1 July 2028. In response to customer feedback, customers opting in to a dynamic connection would be able to opt-out of two-way tariffs. The AER rejected our tariff structures for two-way tariffs and requested additional changes and more information to be provided in the Revised TSS in order for it to be capable of acceptance. Our revised TSS does not make these changes but instead extends the introduction of two-way tariffs to beyond the 2025-30 period.
Tariff assignment for SAC Large business customers	Offer TOU Energy tariffs for SAC Large customers with demand greater than 120 kVA and consumption less than 160 MWh per annum.	In response to the AER's Draft Decision we have introduced a new optional TOU Energy tariff for SAC Large customers with demand greater than 120 kVA and consumption less than 160 MWh per annum, from 1 July 2025.
Flexible load tariffs	Include further description of control arrangements that are contained in the Queensland Electricity Connections Manual (QECM), including the relationship between the QECM and TSS, and the extent to which control arrangements influence tariff options, including the new flexible load tariffs.	Our Revised TSS includes further information on the new residential and small business flexible load tariffs. Additional information regarding the QECM is also included.

Table 1: How we have responded to AER's Draft Decision on network tariffs

Issue in draft decision	Changes requested by the AER	Our response
Grid-scale storage tariffs 	Provide further detail on grid-scale storage tariffs, including more detail on the critical peak pricing mechanism.	Our Initial TSS proposal included two grid-scale storage tariff structure options, the Dynamic Price Storage tariff and Dynamic Flex Storage tariff. The Dynamic Flex Storage tariff (with no critical peak prices) will be offered as an optional tariff from 1 July 2025. We consider this simplified tariff structure proposal compliant with the NER and capable of understanding by customers and retailers. The Dynamic Price Storage tariff incorporating critical peak period import and export charge components will be offered as a trial tariff from 1 July 2025. In addition, a complementary secondary tariff incorporating critical peak period import and export reward components will be trialled from 1 July 2025. The secondary tariff will be made available to customers on both the Dynamic Flex and Dynamic Price Storage tariffs.

1.2 The role of tariffs in delivering better outcomes for customers

Our revenues are capped, meaning that changing our assignment arrangements, tariffs and pricing components can only be set in a way that recovers forecast allowed revenues. However, we are expected to ensure our tariffs are set efficiently and reflect the efficient costs of providing services to each class of customer.

More efficient prices allow the allocation of revenues in a way that:

- minimises cross subsidies by ensuring recovery is between stand alone and avoidable costs of supply
- signals through higher revenue allocation to customer usage decisions that result in likely future network costs (represented by some indication of long run marginal cost (LRMC)), and
- promotes least distortionary residual recovery by allocating revenues in a way that has the least influence on user's energy decisions.

Efficient pricing has the potential to encourage more efficient use of the network which can help reduce the need for additional investment over time. In fact, it is one of the few levers a network has to incentivise and encourages better utilisation of the network. As all customers ultimately pay for these network upgrades, improved pricing arrangements that encourage more efficient use of the network can lead to lower network costs for all customers over time.

Any structural change will result in changes to individual prices and inevitably positive and negative impacts for different customers. Network tariffs are expected to be capable of being reasonably understood and promote efficient usage.

Changes implemented by the AER's Final Decision on Ergon Energy Network's distribution determination for the 2020-25 regulatory control period represented a significant but transitionary step towards more efficient tariff structures and assignment arrangements. This is particularly the case for residential and small non-residential customers with the AER's decision to implement time of use (TOU) Demand tariffs, but with a transitional demand signal. All customers within this group with capable meters are now assigned to network tariffs that reflect lower prices during most of the day and higher prices in the afternoon and evening (where triggers for network investment are strongest). As a result of these changes, over a third of our customers are currently assigned to some form of cost-reflective network tariff structure.

1.3 Overview of our Tariff Structure Explanatory Statement

Table 2 provides an overview of our Explanatory Statement chapters and the purpose of each chapter.

Table 2: Overview of our Explanatory Statement

Chapter	Title	Purpose
1	Overview	Overview of this statement
2	Our customers	Our role in supplying energy to customers and the areas of supply
3	The impact of change on our network and tariff strategy	Outlines the changes to our operating environment
4	Addressing opportunities and challenges from change	Our response to changes in our operating environment
5	Engaging with our customers	Demonstrates our commitment to customer engagement and what we heard from our customers and key stakeholders
6	Consultation outcomes: revision to our tariffs	Our revised changes to our Explanatory Statement for the 2025 to 2030 regulatory control period
7	Network bill outcomes for customers	Overview of our approach to customer impact analysis, including customer bill impacts
8	Compliance with the Pricing Principles	Demonstrates compliance with the Pricing Principles
App. A	Dynamic Connections	Overview of our Dynamic Connections processes
App. B	Queensland Electricity Connections Manual (QECM)	Overview of the QECM and how the QECM interacts with the TSS
App. C	Responding to the AER's specific concerns around appliance control	Our response to the AER's specific concerns around appliance control
App. D	Flexible Load Tariff	Overview of the Flexible Load Tariff terms
App. E	Tariff trial notification	Our intended Tariff Trials for the 2025-2030 regulatory control period
App. F	Process map in relation to a Dynamic Connection Agreement	Overview of the Dynamic Connection Agreement process
App. G	Case study – Dynamic Flex Storage tariff	Demonstration of our Dynamic Flex Storage tariff
App. H	Avoided Transmission use of System (TUOS) payments to embedded generators	Overview of Avoided TUOS payments
App. I	Summary of all issues raised by the AER with our response	Summary and our response to all issues raised in the AER's Draft Decision
App. J	Network Pricing Working Group (NPWG) summary	Summary of the NPWG's response to the AER's Draft Decision and our response for the Revised TSS
App. K	Outline of how the QECM relates to flexible load tariffs	A table outlining how the QECM interacts with the flexible load tariff

1.4 Summary of key changes to our assignment rules and tariffs in 2025

Our changes continue a trend nationally toward more efficient network tariff structures aimed at ensuring more efficient outcomes for all customers in relation to the use of electricity networks.

Table 3 below summarises the key changes to tariff structures and assignment arrangements that will apply from 1 July 2025.

Table 3: Summary of key changes in our Revised TSS

Key Change	Description
TOU	Our TOU windows will change from 1 July 2025. For residential customers we are targeting zero distribution charges for energy used between 11am-4pm daily. A peak rate will continue to apply to the 4pm-9pm peak window daily. Shoulder rates will apply at other times. For our small business customers, we are targeting zero distribution charges for energy used 11am-1pm daily. A peak rate will apply to a new window of 5pm-8pm weekdays only with shoulder rates applying at other times. Large businesses will move to a default tariff structure aligning to the same windows as small business customers. Connection Asset Customers (CAC) will also have the option to move to network tariffs with TOU windows consistent with small business customers from 1 July 2025.
Tariff Streamlining	We will withdraw several tariffs that have either been closed for some time, have few customers assigned to them or that no longer feature in our future network tariff direction.
Two-way Tariffs	Any implementation of two-way tariffs will occur beyond the next TSS period. This will allow time for significant AER proposed reforms to be resolved and embedded thus ensuring customers are brought along with clear information and education.
Load Control	Some tariffs are offered to support customer adoption and retention of active device management. Active device management (including controlled load) provides us flexibility to manage system wide and localised issues in a way that defers or avoids traditional network investment, which can lead to lower network costs for all customers. We will expand tariff options for customers subject to active device management. Flexible Load Tariffs will be introduced from 1 July 2025 allowing customers to access cheaper rates for controlled appliances, while also maximising the benefit of using their appliances on a primary tariff with behind the meter solar photovoltaic (PV) and storage technologies.
Changes to default tariff arrangements and additional tariffs	We have changed the default assignment arrangements for Standard Asset Customers (SAC) Small with a smart meter from TOU Demand and Energy to TOU Energy. This is in response to the AER's rejection of demand peak charging mechanisms for our default tariffs. For SAC Large customers we have added an optional TOU Energy tariff in response to the AER's Draft Decision.
Storage Tariffs	We will introduce new tariffs for customers who exhibit both load and generation characteristics following successful trials. We will also offer trials of tariffs which have dynamic price elements.

2 OUR CUSTOMERS

2.1 Our role in supplying energy to our customers

Electricity is provided across Queensland through different organisations that generate energy, transmit the energy, distribute energy and provide energy related retail services to end-user customers, some of whom also self-generate additional energy through solar panels.

The costs of our services are recovered from retailers based on each customer's usage and the distribution network tariff to which the customer has been assigned. The network tariff relates to the combination of charges which, when applied to a customer's usage, will determine how much we bill a retailer.

We have several tariffs to which we assign customers. Both the rules for assigning customers and the charging components are approved by the AER.

There are different types of charges that make up network tariffs, namely;

- Fixed daily rates (dollars per day) are applied regardless of energy usage and are common to most of our tariffs.
- Volume rates (dollars per kilowatt hour (kWh)) are applied to the amount of energy used over a period.
- Demand charges (dollars per kilowatt (kW)) or dollars per kilovolt amps (kVA)) are usually applied to the highest recorded demand within a period.

Further details of our charging mechanisms are included in Chapter 4 of our TSS and the Network Tariff Guide.

The proportion of a customer's bill representing distribution costs will differ depending on the tariff the customer is on, and how much energy the customer uses. For some tariffs the end bill will depend on the times that the customer uses energy.

Retailers recover network charges through the bill they send to customers. Retailers are not obliged to pass on our network tariff structures to customers, as our charges comprise only a portion of the total bill. This can mean that the tariff structures we apply are not always passed through to the end customer.

2.1.1 Retail arrangements in regional Queensland

The Queensland Government applies special arrangements aimed at ensuring most customers in regional Queensland face lower electricity bills relative to the cost of supply. Notified Retail prices for small customers set by the Queensland Competition Authority based on the cost of supply in South East Queensland for those customers choosing Ergon Energy Queensland Pty Ltd (Ergon Retail) as their energy retailer. Retail prices for many large customers are based on the Ergon Energy Network East pricing zone with the lowest cost of supply. This impacts how our network tariffs are passed through to the end use customer.

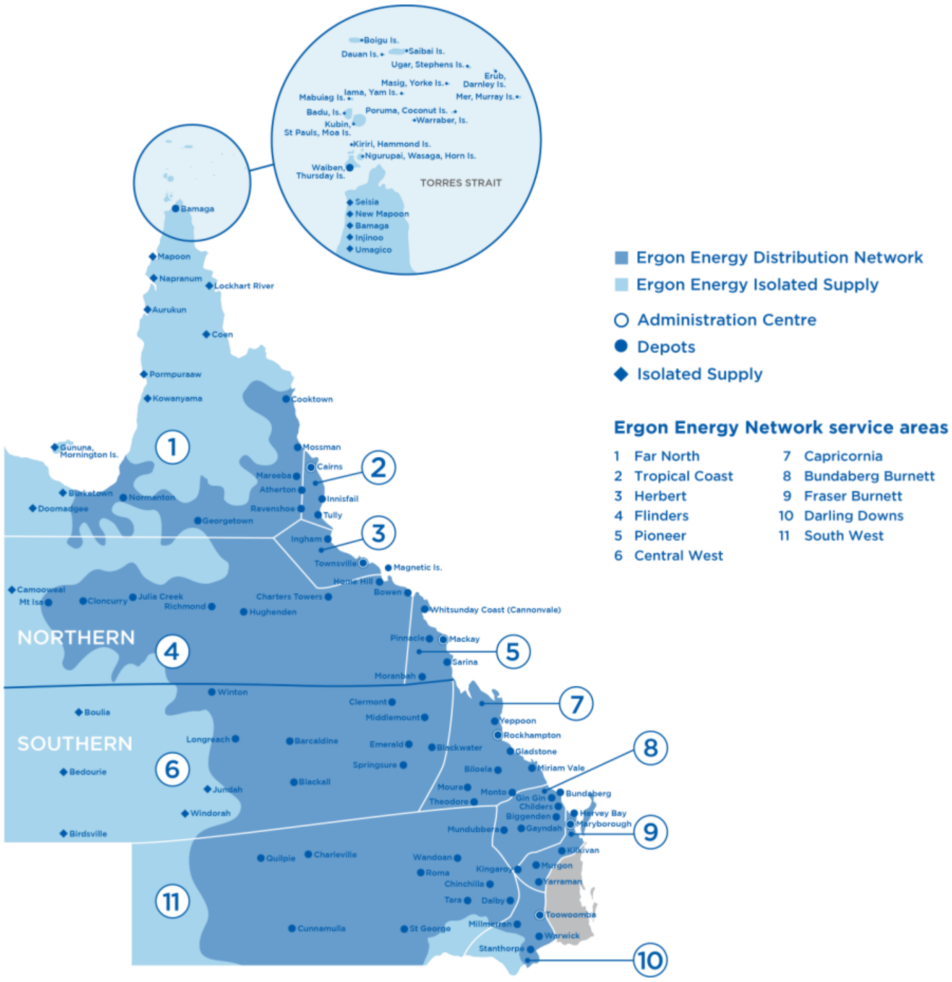
Customers in regional Queensland supplied by Ergon Retail are assigned to a default regulated retail tariff that does not necessarily reflect the underlying network tariff structure we apply to the retailer. However, customers with smart meters have the option to move to different regulated retail structures that are more closely aligned to our network tariff structures.

As noted in our Regulatory Proposal, several small business transitional tariffs will be withdrawn on 30 June 2026. Several gazetted transitional retail tariffs mirror the structure of the tariffs we propose to withdraw. Extending the tariffs a further 12 months will assist with the administrative process for setting notified prices in regional Queensland. Further details are available in Section 6.6.

2.2 Who we supply

Ergon Energy Network is a subsidiary company of Energy Queensland Limited (Energy Queensland), a Queensland Government Owned Corporation, and is the electricity distribution network service provider (DNSP) for regional Queensland. We own, operate, and maintain the 'poles and wires' that deliver power to approximately 790,000 homes and businesses from the State's expanding coastal and rural population centres to the remote communities of outback Queensland and the Torres Strait.

Figure 1: Our Service Area



We have a wide diversity of customers who use the network for different purposes. We classify customers according to their connection type, connection attributes and usage characteristics. Most of our customers are residential customers who, with other small and larger non-residential customers connect to our LV network.

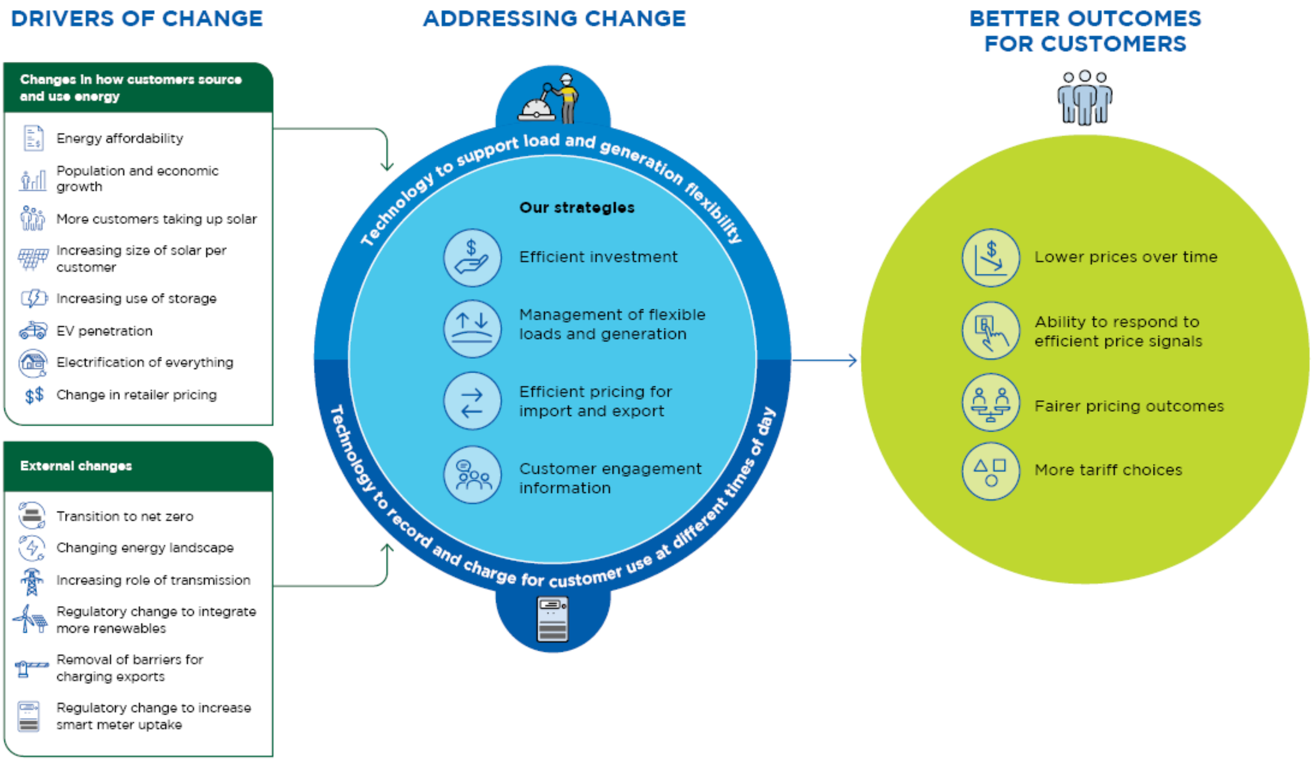
Our annual network tariff rates are set based on a revenue allocation to each tariff class. This revenue allocation is based upon the underpinning requirements to service that tariff class. In our engagement, some customers have observed that the relativity between our tariff class revenues may not be reflective to the contributions made to the larger Queensland economy. For example, small business accounts for over 97 per cent of businesses statewide,[2] however account for a relatively small amount of our annual revenue.

[2] Queensland Government, [Queensland Small Business Month | Business Queensland] (retrieved 29 October 2024).

3 THE IMPACT OF CHANGE ON OUR NETWORK AND TARIFF STRATEGY

Our Initial TSS outlined how our engagement with customers centred on the significant change in the way customers use energy, as well as transformational change in the energy sector itself. The link between change factors, impacts on our network and our technology and pricing strategies to enable better outcomes for customers is outlined in Figure 2.

Figure 2: Strategies to address drivers of change



Our Initial TSS provided context for drivers of change including historic trends. Table 4 summarises each of these drivers.

Table 4: Key drivers of change

Change factor	Explanation
Changing customer needs	• With increased uptake of renewables and other technologies customers are rapidly changing how they use the electricity network and what they expect from it. • Network investment is being influenced by rising electricity prices and cost of living pressures, increased uptake of distributed energy resources and increasingly harsh climate conditions.
A growing economy and population	• While the global economy faces increased uncertainty and volatility, our forecasts assume growth reflecting the unwinding of supply constraints, a moderation in inflation levels and continued strong employment growth. • As COVID-19 impacts diminish, we expect new connections to recuperate and stabilise over the next price period, because of buoyant interstate and overseas migration, the upward housing market and growth in Gross State Product.
Continued growth in distributed energy resources	• Queensland leads the world in solar penetration. This trend is likely to continue. • We expect customer investment in battery storage will likely increase as battery costs decline over time.
Electrification of everything	• Increased electric vehicle (EV) uptake as a greater variety of EV types enter the market and their cost moves closer to price parity with Internal Combustible Engine vehicles. • Conversion from gas to electricity as customers switch from gas to electric appliances. • Progressive shift of many sectors towards electrification to achieve net zero commitments.
Cost of living pressures	• Customers want the energy transition to be affordable and fair, with greater choice that will allow them to reduce their energy bills. • Customers do not want to place the burden to pay onto the next generation of customers. • Customers also want us to consider the impact of the energy transition on energy inclusion.
A shift to a renewable energy future	• Almost two-thirds of the traditional generation fleet in the National Electricity Market will retire by 2040 – with the majority replaced by wind and solar generation backed up by battery storage systems and supported by rooftop solar. This will change how the network is managed and operated. • The Queensland Energy and Jobs Plan as well as the Queensland Climate Transition Strategy represent plans to manage the transition from traditional sources of supply to renewables.
Renewable Energy Zones and CopperString	• The Queensland Government Renewable Energy Zone seeks to foster a thriving clean energy economy, create job opportunities across the state and reach renewable energy targets through coordinated energy infrastructure planning and investment. • CopperString 2032 includes a 1,100 km HV electricity line from Townsville to Mount Isa that will connect Queensland's North West Minerals Province to the National Electricity Network.

Change factor	Explanation
Reforms aimed at integrating distributed solar and storage	• On 12 August 2021, the Australian Energy Market Commission (AEMC) made a final determination to integrate distributed energy resources such as small-scale solar and batteries more efficiently into the electricity network. • Clear obligations now exist for networks to support energy flowing in both directions and clarification that export services are a core distribution service. • Networks must now plan for the provision and efficient pricing of export services given the prohibition on export pricing has been removed.
Increasing smart meter population	• Smart meters allow us to explore options for charging higher rates at times when usage is most likely to trigger future investment - and lower rates at other times. • In 2020 we commenced tariff reforms for customers with smart meters. This has resulted in more efficient network prices being sent to retailers for over a third of our customers. • Other policy initiatives have been aimed at fast tracking smart meter penetration so that by the end of the next regulatory control period almost all connections will be via a smart meter.
Retailer pass through of network tariff reforms in 2020-25	• A customer's most regular interaction with the energy supply chain is usually through the payment of their energy bill to a retailer – which includes Ergon Energy Network's distribution network costs. • Retailers are not obliged to pass on distribution network tariff structures to customers, as these costs only represent a portion of the total bill. Nevertheless, establishing more efficient structures for signalling distribution costs has been a high priority reform in energy markets and one which we are now only starting to see the benefit of. • More customers have access to retail tariffs that include time variant prices by virtue of higher penetration of smart meters. • Stakeholders have raised concerns with some retailers moving customers to time variant tariffs without being informed. This is discussed more in the section below.
Retailer take up of optional tariffs	• Throughout the 2020-2025 regulatory control period, the bulk of our residential and small business customers are either assigned to our default TOU demand tariff or are assigned to a flat energy retail tariff if they have a basic meter. • Retailers have largely kept the default assignment arrangements for residential and small business customers (for smart meter customers this is a demand tariff). There has only been a small transition to TOU energy for some residential customers.

3.1 Drivers of change post lodgement

The environment in which the AER's decisions on network tariffs are made is constantly evolving. While the above drivers are still relevant, since the lodgement of our Initial TSS in January there have been policy, media and political developments influencing some stakeholder's appetite and preferences regarding the pace, nature and scope of reform. We outline some of these developments in the sections below.

3.1.1 Focus on energy pricing

In recent times there has been public scrutiny and concern surrounding time-varying retail tariffs.[3]

Key issues raised by stakeholders the media include:

- lack of transparency and heightened confusion for households regarding transfer to tariffs which have different structures to what customers are used to, often without warning or communication, and
- claims that customers face higher bills due to their inability to shift energy consumption to cheaper off-peak periods.

Public media statements often link customer concerns regarding their retail bills with the smart meter rollout and network tariff reform. This has sparked discussions about the fairness of current tariff structures and the need for greater transparency from both energy retailers and regulators in explaining how these charges are applied.

There has been government and policy response to the public scrutiny and concern around energy pricing. For example:

- The Queensland government is seeking to implement better consumer protections for Queensland households including a proposed change to allow regional households who have moved to TOU tariffs following the installation of a smart meter, to now be able to revert back to a flat tariff.[4]
- The AEMC is seeking to improve consumer protections and market transparency, particularly in response to the accelerated deployment of smart meters and rising energy costs.[5] The AEMC published a directions paper outlining the potential for enhanced consumer protections during the accelerated smart meter rollout, including a mandatory three-year consent period for retail tariff changes and requirements for designated retailers to offer flat tariff options.[6]

Many of these debates play out on the national stage and fail to recognise Queensland specific issues. One common misconception is that once customers receive a smart meter they are placed on a demand based TOU tariff. This is not correct. The default network tariff structure for a customer with a smart meter is applied to a retailer. There is no automatic assignment of end use customers to network tariff structures in their retail bill when a smart meter is installed.

In regional Queensland, 98 per cent of customers with smart meters are on retail tariffs that have no resemblance to the network tariff structure. Customers who are on retail tariffs with a network tariff structure are either large customers or customers who choose a network tariff structure. This is because ultimately customers in regional Queensland choose whether to transition from their current retail tariff arrangement (for residential customers tariff 11 any time energy) to an alternative time variant tariff (tariff 12 or 14). On this basis most customers remain on an anytime energy tariff even though the retailer faces a time variant network tariff.

---

[3] See:
ABC, Claims complex power prices 'all pain, no gain' spark calls for tariff rethink - ABC News, (retrieved 29 October 2024).

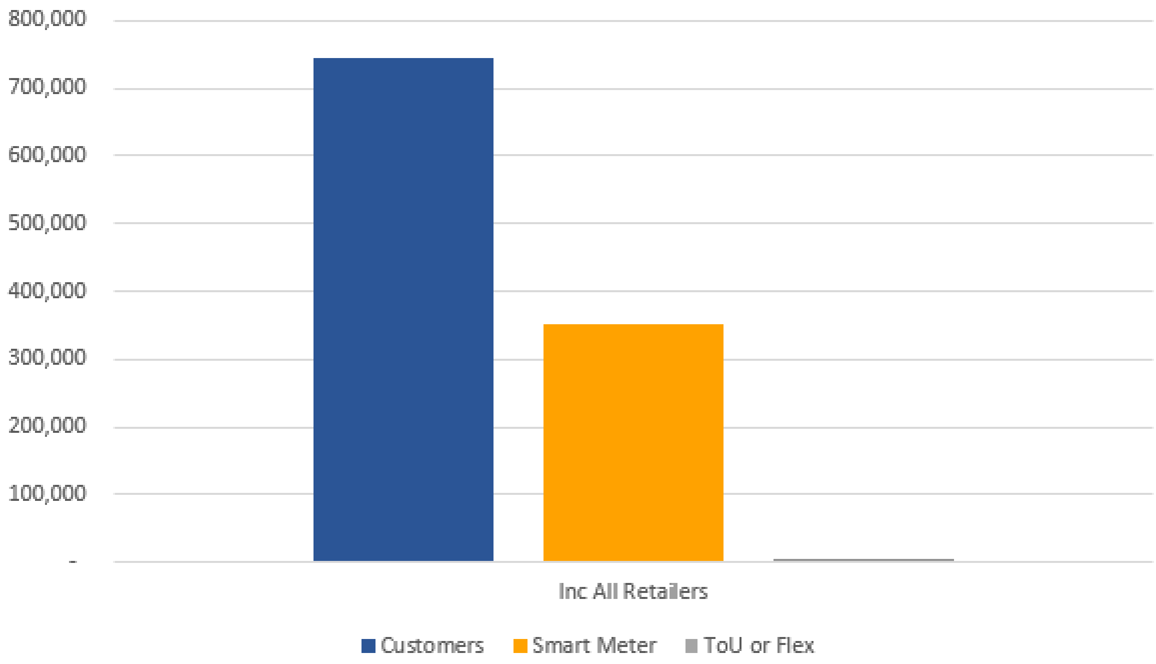
ABC, Power price structures have radically changed, but nobody thought to tell consumers about it - ABC News, (retrieved 29 October 2024).
ABC, Electricity retailers label complex power prices 'perverse' as industry goes to war with itself - ABC News, (retrieved 29 October 2024).

[4] Queensland Government, Miles Government win in stopping energy retailers' smart meter sting - Ministerial Media Statements, August 2024.

[5] AEMC, Accelerating smart meter deployment | AEMC, (retrieved 29 October 2024).

[6] AEMC, National Electricity Amendment (Accelerating smart meter deployment) Rule 2024, Policy, Directions paper, August 2024.

Figure 3: Ergon Energy Network Customers Count



3.1.2 Network utilisation

More recently, the AER and Energy Consumers Australia (ECA) have identified low network utilisation as a source of concern.

The AER has informed us they have a clear preference for network businesses to concentrate on ways to facilitate greater utilisation of their networks prior to seeking approval for augmentation expenditure.[7]

The ECA have suggested that low utilisation is evidence that networks no longer need to augment the network for peak demand in the long-term, thereby making time variant tariffs redundant.[8]

Tariff reforms introduced in 2020 were designed to improve price signals and encourage behaviour to improve network utilisation over the longer term. The current default Transitional Demand tariff approved by the AER provides a signal to improve network utilisation by incentivising customers to better manage their demand, particularly during peak periods.

TOU Energy tariffs, which charge customers based on the total energy consumed within different time windows was also approved by the AER as an optional tariff. While this also incentivises shifting energy usage to off-peak times, the pricing signal is weaker compared to demand tariffs because it focuses on total energy consumption rather than peak capacity use. Customers may still consume large amounts of energy during peak periods without significantly reducing their impact on the network peak demand.

[7] AER, Q&A with the AER (linkedin.com), (retrieved 29 October 2024).
[8] Energy Consumers Australia, report-cost-reflective-network-tariffs-arent-cost-reflective-5.pdf (energyconsumersaustralia.com.au), (retrieved 29 October 2024).

4 ADDRESSING OPPORTUNITIES AND CHALLENGES FROM CHANGE

4.1 Impacts of change

A key role in delivering distribution network services to our customers is to ensure there is enough capacity to supply every household and business on the days when electricity demand is at its maximum. Our Initial Explanatory Statement explains how drivers of change impact our operation of the network. Change factors can influence customer decisions on how they source and use their energy. These decisions have implications for future costs and how the recovery of these costs are allocated across our customer base, including:

- Change factors can influence customer decisions regarding using the network at peak times, increasing the risk of higher costs in the future. Efficient pricing arrangements ensure customers using the network at these peak times pay proportionately more than customers who don't.
- Change factors can influence customers decisions to avoid using energy at certain times. This may result in a redistribution of revenue recovery from other customers. Efficient pricing arrangements aim to minimise distortionary price signals which allow some customers to avoid charges at the expense of higher prices for others.

Our Initial Explanatory Statement outlined several variables that can be impacted by change which can have flow on impacts to costs and revenue recovery. These are outlined in Table 5.

Table 5: Impacts of change

Change factor	Explanation

Network Peak Demand	• System maximum demand provides a useful indicator of aggregate growth trends in peak demand across our network. However, individual zone substation and feeder maximum demand forecasts are more commonly used to identify emerging network limitations in the sub transmission and distribution networks.
	• Demand peaks in different parts of the network are not necessarily coincident. They can vary by location and customer mix (industrial and residential). Setting a single TOU window for an entire distribution network area necessitates trade-offs and can only ever be approximate.
	• Nevertheless, we used historic and forecast intra-day demand profiles to inform the likely timing of peak and minimum network demands for the 2025-30 financial years and found:
	  ◦ Historical peak demands across substations have become more concentrated over the past 10 years, typically occurring around 6 pm.
	  ◦ Future peak demands are projected to occur slightly later in the evening, typically occurring around 7pm over the 2025-30 regulatory control period.

EV uptake and impact on peak demand	• Typical demand for 'wall box' EV charging equipment is around 7kW – equivalent to almost double the typical peak load of an average residential premises. • The impact factored into the forecasts is low initially but increases over time with the growing population of vehicles. EV charging is not expected to provide much offset for minimum demand due to the differences in timing between vehicle charging and peak solar PV generation.

Change factor	Explanation
Minimum Demand	• Minimum demand can best be described as the lowest energy demand across an electricity network at a point in time. • Left unmanaged, lower minimum demands (particularly when experienced with high demands at other times) can create issues around local power quality that can be harmful to customer appliances as well as the network. • Day-time minimum demand windows are increasingly creating reverse power flows in localised parts of our network. Reverse flows can impact power system security, threatening its ability to withstand major events.
Connection Arrangements	• As the energy transition gathers pace and more renewables are connected to the network, updates are required to connection arrangements that reflect changing customer needs and the requirement to cater for these needs while also providing a safe affordable and reliable network.
Integration of new technologies (customer energy and other distributed energy resources)	• The Queensland Energy and Jobs Plan recognises the increasing contribution that customer energy resources will make to future energy systems and markets, providing an opportunity for customers to participate in several ways. • We anticipate that this will lead to greater customer benefits from digital transformation and distributed energy resources responding to new connection options and associated cost reflective tariff options.

4.2 QECM updates to reflect change in technology

Our network tariffs support a range of network management initiatives Ergon Energy Network undertakes to ensure affordable, reliable, and safe energy outcomes for consumers. Some of these initiatives leverage modern technologies to improve the efficiency and management of the electricity network. Examples include active device management and dynamic connection arrangements that allow Ergon Energy Network to manage energy demand more effectively while offering consumers cost-saving opportunities as new technologies and consumption patterns evolve.

Network management initiatives are constantly evolving to reflect new technologies and consumption patterns, with consequential changes incorporated into connection and operational arrangements. Many of the requirements for connecting to and interfacing with our distribution system are contained in the QECM. Recent updates to the QECM and the impacts of these updates on existing and new tariffs became a focus of AER questions and engagement post lodgement.

The QECM and the TSS documents are complementary to each other and serve distinct purposes. The QECM focuses on technical standards and guidelines for connecting customers to the electricity network. Where it does specify certain load management requirements, it does not mandate any specific network tariff. Conversely, all network tariff assignments, charging elements and pricing levels are contained in the TSS and the annual Pricing Proposal.

The QECM needs to keep pace with the changing technological environment and take-up of new and emerging customer energy resources. For this reason, the QECM is updated as needed through a separate process from the AER process for approving tariffs and assignment arrangements. This allows the QECM to evolve as needed, noting any changes in the QECM do not impact elements approved by the AER in the TSS and the annual Pricing Proposal. We provide further information on these issues in Chapter 5, Appendix B, C and K.

4.3 Stand Alone Power Systems

Our Initial Explanatory Statement explained how Stand Alone Power Systems provide an alternative to replacing aging network in some circumstances.

4.4 Network tariff reform and its contribution to change

4.4.1 Summary

Network tariff reform complements other key initiatives aimed at ensuring our customers can navigate to a smarter, renewables enabled network, while driving efficient cost outcomes and fair prices for all our customers.

Electricity pricing is a critical consideration in achieving both efficiency and fairness for all customers. While distribution costs represent less than a third of the average residential bill, network tariff reform – in terms of structure and allocation – is seen by customers, regulators and policy makers alike as a change agent to delivering on efficiency and fairness outcomes.

More efficient tariff designs seek to align higher charges for using network capacity in the periods most likely to result in additional investment. This ensures that the recovery of future investment is allocated more to customers who use the network at peak times. If more customers, in response to higher charges choose to use less energy at peak times to save money, this is likely to defer the need for future investment, keeping network costs lower for all customers.

Finally, because our revenues are capped, prices set higher to recover more revenue in peak periods must be offset by lower prices in other periods, providing even stronger pricing signals for customers to move energy use outside of peak periods.

During the 2025-2030 regulatory control period, our business will likely pivot to a new phase in electricity tariff adoption, where the proportion of customers who will be able to receive and respond to more efficient pricing structures (through rollout of smart meters) will move from the minority to the majority. This change removes important barriers that for some time have slowed the pace of network pricing reform relative to other changes in the sector over the last decade.

However, with all change comes impact. Our tariff reforms have been tested with customers to ensure the pace of change is proportional to customer preferences and concerns regarding any impacts.

4.4.2 Future network costs linked to network tariff reform

Policy makers and regulators rank transitioning to more efficient network tariffs high on the agenda of key market reforms on the basis that more efficient pricing of the network promotes more efficient utilisation of the network and has the potential to reduce the need for investment over the long term. Our NPWG encouraged us to demonstrate why changes to network tariffs now will benefit customers over the long term.

We engaged Dynamic Analysis to model long-term expenditure outputs that result from different scenarios of price responsiveness and dynamic load control. Their analysis suggests that tariff reform:

- provides more equitable outcomes as changes in behaviour reward both the customer in terms of lower prices and the network in terms of less pressure on peak demand, and
- has benefit for all customers over the long term, compared to no change especially when incorporated with dynamic control and load flexibility.

5 ENGAGING WITH OUR CUSTOMERS

5.1 Summary

In this section we outline how our engagement has informed the development of the proposed tariffs for the 2025-30 regulatory control period. Customer input and preferences regarding network tariffs have been a key focus of our engagement due to the significance of potential changes for network tariffs and the likely impacts from those changes.

Our Initial TSS was influenced by the perspectives gained from the variety of engagement sessions with different customers and stakeholders across each of the customer segments. This commenced in 2021 with initial engagement developing and refining network tariff options as well as frameworks for assessing customer impacts. We have built on these initial works to deliver an extensive engagement program across a range of customer segments, customer and industry representatives. This included expansion into dedicated engagement streams for residential and business customers as well as retailers.

A full report of engagement activities undertaken between the end of October 2022 and 31 January 2024 is included in the Customer and Stakeholder Engagement Summary report.[9]

5.2 Phase 5 – post lodgement engagement

5.2.1 Stakeholder engagement groups

Network Pricing Working Group (NPWG)

In July 2023, we established the NPWG to assist us in co-designing our TSS for the 2025–30 regulatory control period. Our Initial TSS provides information on the NPWG activities in 2023 and their important contribution to our final position on tariff structures and assignment arrangements.

Revised focus of NPWG post lodgement

In recognition of the value and contribution that the NPWG brought to the development and critical review of network tariff strategy we took the opportunity to transition the NPWG to a representative forum that would assist us in the finalisation of our 2025-30 TSS. An open expression of interest process resulted in an expansion of the NPWG membership with broadened representation.

[9] Ergon - 2.03 - Customer and Stakeholder Engagement Summary report - January 2024 | Australian Energy Regulator (AER) (retrieved 5/11/2024).

Table 6 lists the various organisations which make up the customer and stakeholder cohorts of the NPWG.

Table 6: NPWG Members

NPWG Members	
Australian Energy Council - This organisation represents the industry or the energy sector.	Ergon Energy Retail - This organisation represents our retail cohort of customers.
National Electrical and Communications Association - This organisation represents the industry or the energy sector.	National Senior Australia - This organisation represents our seniors and vulnerable customers.
Council of the Ageing - This organisation represents our seniors and vulnerable customers	Energy Users Association of Australia - This organisation represents the industry or the energy sector.
Capricorn Enterprise - This organisation represents more than 120,000 residents from the Capricorn Coast Region, including Rockhampton and coastal communities from Yeppoon to the Keppel group of islands.[10]	St Vincent de Paul – This organisation represents our vulnerable customers.
Bundaberg Regional Irrigators Group - This organisation represents our large business customers.	Business Chamber QLD - this organisation represents our customers from small, medium and large businesses.
Queensland Electricity Users Network - This organisation represents regional industry.	Independent Subject Matter Expert - This independent subject matter expert represents the industry or the energy sector.

Since formation, the NPWG's focus has been toward providing consensus positions on issues raised either through the AER Issues Paper, customer and stakeholder submissions and/or responses, and the AER Draft Decision.

Reset Reference Group

The Reset Reference Group (RRG) is a group made up of representation of customer advocates from their customer cohorts or industry professionals to provide customer cohorts a voice for the option to have access to safe, reliable and affordable energy.

Table 7 lists the members of the RRG.

[10] See https://capricornenterprise.com.au/ (retrieved 12/11/2024).

Table 7: RRG Members

RRG Members	
Council of the Ageing - This organisation represents our seniors and vulnerable customers	Energy Users Association of Australia - This organisation represents the industry or the energy sector.
Capricorn Enterprise – This organisation represents more than 120,000 residents from the Capricorn Coast Region, including Rockhampton and coastal communities from Yeppoon to the Keppel group of islands.	St Vincent de Paul – This organisation represents our vulnerable customers.
Independent Subject Matter Expert - This independent subject matter expert represents the industry or the energy sector.	

The RRG members also participated as members on the NPWG. Through the NPWG members were able to share their comments, reflections on important issues that the group felt needed additional analysis or information to be able to reach a super majority point once voting deliberations were asked.

In the RRG submission earlier this year to the AER, the RRG wrote that they had seen significant progress on:

- impacts on various groups, including those households with “traditional” energy use i.e. those without solar photovoltaic systems and other emerging households that are taking up newer consumer energy resources, such as those households with solar / home battery / EV’s; modelling should include an overlay of two-way reward, and export pricing with a basic export limit
- exploration of impacts on vulnerable groups, in particular renters and low-income households, and
- the do-nothing option, i.e. keeping the current tariffs and show how future costs will be allocated under this scenario.[11]

Separately, distributional impacts of proposed tariff reforms remained a priority throughout 2023 for the RRG members through the NPWG and detailed modelling was provided to the group in September 2023, noting the complexity of the issue required more informed engagement processes.[12]

[11] RRG, Engagement Report for the 2025-2030 Ergon Energy Network Regulatory Proposal, March 2024, page 28.
[12] RRG, Engagement Report for the 2025-2030 Ergon Energy Network Regulatory Proposal, March 2024, page 27.

Consumer Challenge Panel

The Consumer Challenge Panel advises the AER on whether the long-term interests of consumers are being considered in regulatory proposals, including the TSS and in the AER's decision making processes.[13]

In May 2024, the Consumer Challenge Panel submission to the AER states the following:

- Overall, Ergon Energy Network's TSS accurately reflects the feedback arising from the various channels of consumer engagement.
- Consumers appreciated the reasoning behind the wider use of time-varying tariffs and the need to strengthen the peak price signal.[14]
- It is critical to establish a clear and effective communication and engagement plan with retailers and customers to hopefully clear the way for an effective introduction and adoption of proposed tariffs.
- The AER and Ergon Energy Network should articulate a communication strategy for the tariff changes.[15]
- Given recent events in the community regarding energy tariffs, for successful tariff reform customers need to understand their tariffs so that they can optimise their benefits or at least minimise negative impacts.
- The implementation of proposed tariffs must be accompanied by effective communication strategies across the industry, otherwise all good intentions are doomed to fail.[16]

5.3 AER Draft Decision

5.3.1 Summary of response to engagement

In the AER's Draft Decision Overview, the AER observed that we have generally engaged well with customers and stakeholders in developing our 2025–30 TSS.[17]

[13] AER, Better Resets Handbook Towards Consumer Centric Network Proposals, December 2021, page 2.
[14] Consumer Challenge Panel, Advice to the AER regarding the Energex and Ergon Energy (Energy Queensland) regulatory proposals 2025-30, Response to the Proposals and Issues Paper, May 2024, page 34.
[15] Consumer Challenge Panel, Advice to the AER regarding the Energex and Ergon Energy (Energy Queensland) regulatory proposals 2025-30, Response to the Proposals and Issues Paper, May 2024, page(s) 34–35.
[16] Consumer Challenge Panel, Advice to the AER regarding the Energex and Ergon Energy (Energy Queensland) regulatory proposals 2025-30, Response to the Proposals and Issues Paper, May 2024, page(s) 34–35.
[17] AER, Ergon Energy and Energex Electricity Distribution Determinations 2025 to 2030 – Attachment 19 Tariff structure statement, Draft Decision, September 2024, page 3.

5.3.2 Summary of AER Draft Decision

While accepting most elements of the Initial TSS, the AER's Draft Decision was not to accept our tariff structures or assignment arrangements in several areas, expecting changes be made in our Revised TSS to make it capable of acceptance. Most of the changes relate to five key areas:

- Small customer default tariff.
- Additional tariff options for customers consuming between 100MWh and 160MWh per annum with demand greater than 120kVA.
- Two-way tariff structures, transition and interaction with dynamic connections.
- Storage Tariffs – pricing arrangements and quantum of fixed charge.
- Link between tariff assignment arrangements and connections associated with active device management and load control.

The AER also made a number of recommendations for Ergon Energy Network to provide additional information in our Revised TSS to further support or justify changes made, or alternatively to respond to stakeholder concerns.

Appendix I provides a summary of all the issues raised by the AER and our response.

5.4 Engagement activity by issue

5.4.1 Small customer default tariff

The AER's Draft Decision is to reject our current and future assignment arrangements for residential and small business customers.

Pre-lodgement engagement and Initial TSS

As retailers are free to choose between peak charges based on energy and peak charges based on demand, our engagement with customers focussed more on customer interest in the windows for setting peak and off-peak rates rather than the charging mechanism itself. During consultation we received mixed feedback from retailers regarding demand tariffs generally. However, it was acknowledged that:

- retailers had the option to transfer any customer assigned to a transitional demand tariff to either a TOU Energy tariff or a (non-transitional) demand tariff.
- despite this option being available from 2020, there have been very few requests from retailers to transfer customers to TOU Energy tariffs.

In pre-lodgement engagement with the AER, there was minor concern over longer term movements away from TOU energy pricing, but general comfort to maintain tariff assignment arrangements as long as optionality was available.

Our Initial TSS retained the assignment arrangements that apply for the current period. The Residential/Small Business Transitional Demand Tariff was renamed to the Residential/Small Business TOU Demand and Energy tariff. Tariff structures and charging parameters were broadly consistent with current default tariffs. Changes reflect customer preferences for revised windows and strength of price signals. Assignment arrangements were broadly modified for basic meter upgrades to allow more time for retailers to inform customers of choice regarding their retail tariff options. New customer assignment arrangements remained the same.

The Residential TOU Energy tariff continued its optional status in the current period, with changes mirroring the default tariff.

Similar arrangements applied to small business customers on equivalent tariff structures.

Issues raised post lodgement

The AER's Issues Paper noted that tariff reform plays an important role in encouraging more efficient use of the network, which in turn can lead to lower network costs for all customers. While recognising that Ergon Energy Network had met expectations in pursuing incremental tariff reform, the Issues Paper questioned whether demand tariff structure (in place as a default since the AER approved them in 2020) balanced the pace of reform with customer impacts. The AER also noted that tariffs were targeted at retailers who package tariffs with other costs.

The AER also raised concerns about plans beyond 2030 to only offer demand network tariffs, but acknowledged this was not an issue they needed to address for the 2025-30 regulatory control period.

While changes to all TOU windows were supported, some submissions to the AER raised issues with the structure of the tariff that the AER introduced as the default tariff in 2020. The Electric Vehicle Council (EVC) stated that they were pleased to see a range of TOU tariffs being offered across a range of customer groups.[18] The South East Queensland Community Alliance preferred TOU volume tariff charging over demand but made no comment on whether that required a movement of all customers to the TOU optional tariff.[19]

Retailers such as Red Energy and Lumo recognised that TOU Energy tariffs were available but did not support demand tariffs as a default option for the residential segment.[20] Origin was of the view that customers needed to understand the tariffs better to optimise benefits (or minimise negative impacts) and this was only possible with better education and sufficient penetration of "demand response technology".[21]

This was consistent with feedback received by these same retailers when we released our draft plan in September last year, although we note that in our one-on-one consultation with retailers on our draft plan, not all retailers supported a move to TOU Energy as the default tariff.

Both the NPWG and the RRG supported changes we implemented in response to our customer engagements of default on TOU Demand and Energy tariffs with revised windows and the long-term plan to move to demand or capacity charge only and no longer offer energy only tariffs.[22]

Engagement with NPWG prior to the AER Draft Decision

This issue was discussed with the NPWG at our July meeting prior to the AER's Draft Decision. While demand-based tariffs have been the default for small customers with smart meters in Queensland since 2021, there was recognition that a minority of customers in regional Queensland are only now starting to see the price structures on their bill.

There was general acknowledgement that pricing arrangements are complex and can be difficult to understand and that there is a need for customer education. Nevertheless, the consensus view was that TOU demand tariffs provide a better price signal to customer than TOU energy-based tariffs. When complemented by appropriate customer protections and education these structures

[18] EVC Submission to AER on the Ergon Energy Network regulatory proposal 2025-30, May 2024, page 3.
[19] South East Queensland Community Alliance, SEQCA - Submission - 2025-30 Electricity Determination – Energex and Ergon Energy Network - May 2024.pdf (aer.gov.au), (retrieved 31 October 2024).
[20] Red Energy and Lumo Energy, Red Energy and Lumo Energy - Submission - 2025-30 Electricity Determination - Energex & SA Power Networks - May 2024_1.pdf (aer.gov.au), (retrieved 31 October 2024).
[21] Origin Energy, Origin Energy - Submission - 2025-30 Electricity Determination - Energex, Ergon & SA Power Networks - May 2024_1.pdf (aer.gov.au), (retrieved 31 October 2024).
[22] Energy Queensland RRG, Submission on Ergon Energy and Energex electricity distribution regulatory proposals 2025–30 and the Australian Energy Regulator's Issues Paper, May 2024, page 65.

provide a better long-term outcome for customers. On this basis Ergon Energy Network's assignment arrangements for the 2025-30 regulatory control period were supported.

AER Draft Decision and further consultation

The AER's Draft Decision accepted the changes in TOU windows for our smart meter tariffs but rejected the continuation of demand-based tariffs as the default tariff for residential and small business customers. The AER used clauses 6.18.5(h) and 6.18.5(i) to in justify the decision to reject the assignment arrangements.

Clause 6.18.5(h) requires Ergon Energy Network to consider the impact on retail customers from changes in tariffs from the previous regulatory year. This clause allows Ergon Energy Network to vary tariffs that currently comply with the NER, to the extent that Ergon Energy Network considers reasonably necessary having regard to:

- desirability to comply with the Pricing Principles
- the extent to which retail customers can choose the tariffs 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.

In our view tariff assignment arrangements for residential and small business customers in our Initial TSS were consistent with the above NER clauses. The default tariff included in the Initial TSS for residential and small business customers varies in relation to the TOU windows which the AER has accepted. There is no change to its compliance with the Pricing Principles or optionality for customers from what was approved by the AER in 2020-25 Final Decision.

The AER's Draft Decision is therefore inconsistent in that it rejected the default tariffs it approved in the 2020-25 Final Decision for Ergon Energy Network and also approved for New South Wales distributors in 2024. In reversing regulatory precedent, the AER notes submissions, mainly from retailers regarding the ability of the customer to understand, mitigate or respond to the tariff. Based on feedback from some retailers, the AER determined that the TOU Energy tariff be adopted as the default tariff for the Revised TSS.

The AER appears to request that this change be applied retrospectively meaning that all customers previously assigned to the transitional demand tariff will be reassigned to the TOU Energy tariff.

To support its decision, the AER cites the following considerations:[23]

- A RACE for 2030 report in November 2021 suggesting that household understanding of the energy system and the relationship between behaviour and energy use is low, and demand tariffs only add to the complexity, making it harder for customers to understand their bills.
- The AER claims that retailers typically mirror demand-based network charges with demand based retail prices and because of this customers facing demand tariffs will increase sharply as meter penetration escalates.
- While the current default tariff is a demand-based tariff, the AER suggests the signals are muted. From 2025 the AER suggests customers would "face more cost reflective tariffs" for the first time because the rates put forward by Ergon Energy Network to provide efficient network signals.
- While the AER acknowledges that retailers can opt out of a default tariff, because customers or retailers may be disengaged, assignment will likely occur for a period before any reassignment occurs.

[23] AER, Ergon Energy and Energex Electricity Distribution Determinations 2025 to 2030 – Attachment 19 Tariff structure statement, Draft Decision, September 2024, page 19.

Response to AER’s Draft Decision

The AER’s Draft Decision not to approve our assignment is based on their view that we did not comply with the Pricing Principle outlined in clause 6.18.5(h), because in the AER’s view is that there is a more preferable assignment arrangement.

TOU Demand tariffs have been the default in Queensland since 2021, but customers are only now starting to see this tariff structure reflected on their bill. We are aware that pricing arrangements are evolving and can be challenging for retailers and there is a need for customer education. This relates to TOU pricing generally, not just TOU demand pricing.

Our views differ from the AER in respect to demand-based tariffs. Relative to TOU energy tariffs we consider TOU demand tariffs better meet the Pricing Principles and National Electricity Objectives (NEO) for the following reasons:

- Future network costs are driven more by demand at peak times. Demand-based pricing at peak more accurately reflects the cost of providing electricity at peak times. Energy based pricing of peak allocates future network costs to all periods in the window, weakening the pricing signal of future network costs in increasing the propensity to avoid the charges by customers most able to afford technology that allows them to avoid volume charges.
- Demand-based pricing encourages consumers to shift their electricity use away from peak periods, which can promote more efficient use of existing infrastructure, supporting the NEO of promoting efficient investment in, and efficient use of, energy services for the long-term interests of consumers.
- Demand-based pricing is more equitable, as customers who contribute most to peak demand (and hence network costs) pay more, while those with lower peak demand pay less. This ensures that those driving infrastructure costs contribute accordingly. Demand tariffs ensure that users pay in proportion to the strain they place on the network.

There is no evidence of the AER’s claim that retailers typically mirror demand-based network charges with demand-based retail prices. Based on AER data, less than two per cent of Ergon Energy Network customers have a retail tariff that passes through the network tariff time variant structure. Almost all residential and small business customers are likely to remain on the flat rate tariff that applies to all other customers.

The AER appeared to place less weight on our engagement with the Voice of the Customer Panel, the RRG, NPWG or our one-on-one conversations with retailers post our retailer forum when considering this issue. Instead, the AER relied heavily on retailer submissions it received through its own formal process.

Retailer concerns are not unique to this decision. The AER had to weigh up retailer representations in our 2020 decision as well as other decisions in New South Wales in 2024. The AER acknowledged that its decision to move customers to TOU Demand tariffs in 2020 was consistent with the NER and, in particular clause 6.18.5(g) which requires tariffs to reflect efficient costs. The AER’s decision at the time recognised the impact on retail customers, adopting a transitional approach to the signalling of the peak charge. The AER’s view at the time appeared to be that as cost reflective network tariffs were deployed to more customers this would be the nudge for retailers to respond innovatively through retail tariffs and other responses that would become available to retail customers.

The same issues were also raised in more recent decisions for networks outside of Queensland but resulted in different outcomes.

In the Evoenergy decision Red and Lumo both submitted that Evoenergy’s demand tariff was complex and would prefer a TOU Energy tariff as the default. However, the AER did not make changes to assignment arrangements for Evoenergy in response to retailer concerns. Rather, it acknowledged that some complexity is inherent in providing cost reflective tariffs.

The AER's decision was that, because Evoenergy demand tariffs met the NER requirements in that they are capable of being incorporated in retail offers, there was no basis for changing assignment arrangements. This is an appropriate interpretation of the NER clause 6.18.5(h). The AER determined that no changes were required as it recognised that Evoenergy had given consideration to customer impacts. The AER's decision also took into account the fact that retailers are able to opt-out their customers from Evoenergy's demand tariff to its alternative TOU tariff.[24]

Similar circumstances exist in Queensland. Evidence suggests network tariffs have been quite capable of being incorporated into retail offers with retailers ultimately responsible for the structure of tariffs they offer to customers. Optional TOU Energy tariffs have been available for retailers wishing to reassign customers away from demand-based tariffs. We considered the need to promote efficiency in tariff design with impacts to customers in consultation with customer representatives.

In our discussions with retailers there is no single unanimous view on this issue. Some retailers are fixated on the demand charge mechanisms, however some retailers raised concerns that any form of time variant tariff (including export charge periods) is difficult for customers to understand and questioned the benefit of these arrangements to small customers.

Other retailers were generally supportive of cost reflectivity of network tariffs, irrespective of the structure. At least one retailer expressed support for TOU demand tariffs over energy based ones, noting its disappointment over last minute changes to structure for one network in New South Wales.

The AER also makes reference to one area in a 241-page RACE for 2030 report '*Rewarding flexible demand: Customer friendly cost reflective tariffs and incentives*'[25] to justify its position that TOU tariffs are a better default tariff for small customers than demand-based tariffs based on complexity grounds.[26]

However, further analysis of the report reveals a much broader scope and very little focus at all on the comparison of demand tariffs with other tariff designs. The report evaluates complexity more broadly, addressing multiple aspects of tariff design rather than just demand tariffs. Specifically, the report discusses the need for tariffs that support flexible demand, recognising that both TOU energy and demand tariffs play roles in incentivising household electricity flexibility. The report emphasises:

- That both TOU and demand-based tariffs offer significant opportunities to shift consumer behaviour, which can reduce system-wide costs and integrate more renewable energy.
- A need for comprehensive pricing reforms that account for flexibility and customer engagement, without concluding that complexity automatically disqualifies more advanced tariff models like demand tariffs.
- the importance of customer engagement in any tariff reform without preferencing one structure over another.

Importantly, the report argues that when designed with customer-friendly incentives and technologies, even more complex pricing structures can achieve better outcomes for both consumers and the network. This suggests that the complexity argument might be outweighed by the long-term advantages of more comprehensive tariff designs, including demand tariffs, especially as smart meters and digital tools evolve to support customer understanding and participation.

[24] AER, Evoenergy Electricity Distribution Determination 2024 to 2029 – Attachment 19 Tariff structure statement, April 2024, page 6.
[25] Race for 2030, Rewarding flexible demand: Customer friendly cost reflective tariffs and incentives, Final report, November 2021.
[26] AER, Ergon Energy and Energex Electricity Distribution Determinations 2025 to 2030, Attachment 19 Tariff structure statement, September 2024, page 19.

On this basis we consider the AER's reference to the report in support of its rejection of demand tariffs disregards other considerations emphasised in the report. We also note that the RACE for 2030 analysis conducted in 2021 has not been universally persuasive, especially in earlier AER decisions involving Ausgrid and Evoenergy.

The AER has requested a retrospective assignment to the TOU Energy tariff for over 650,000 Ergon Energy Network customers currently on the transitional demand tariff. We have noted that retailers already have the option to make this change at any time of their choosing.

To the extent that materially changing the structure of the default tariff for new and upgrading customers is necessary, it would make more sense that the prerogative to reassign customers already on a cost reflective structure remain with retailers, not retrospectively changed through networks under the direction of the AER to mandate reassignment. Such a unilateral decision suggests retailers, in some way, are not making the right decision on how their customers are currently assigned, and over-riding this decision without full knowledge of the relevant considerations behind a retailer not exercising their option to opt-in to the TOU Energy tariff in the current regulatory control period.

Outcomes we have included in our Revised TSS

Our Revised TSS changes the default tariff for new SAC Small connections and smart meter conversions from a TOU demand and energy tariff a TOU energy tariff.

We have not applied the AER's Draft Decision retrospectively. Customers assigned to a default demand based tariff will remain on the same structure, with retail discretion to reassign existing smart meter customers to a TOU energy tariff if they choose. Retention of retailer choice in this instance promotes more efficient, competitive and equitable outcomes than a unilateral reassignment based on the submission of a few retailers.

5.4.2 Additional tariff options for customers consuming between 100MWh and 160MWh per annum

Different network tariffs apply in Ergon Energy Network depending on whether the customer is classified as a Small Customer or a Large Customer. A Small Customer includes a customer who is a business customer who consumes energy below the upper consumption threshold (S7(1)). The upper consumption threshold is 100 MWh per annum (S7(2)). Thresholds for determining tariff assignments (SAC Small and SAC Large) is legislatively set and determined under the National Energy Retail Regulations.

The default tariff for SAC Large customers is the TOU Demand and Energy tariff. On 1 July 2025 all smart meter SAC Large customers will be reassigned to the default TOU Demand and Energy tariff. SAC Large customers will have the ability to opt-out of the default tariff and request reassignment to the optional Demand Small tariff or the Primary Load Control tariff. There is currently no optional TOU Energy tariff available for large customers.

Issues raised post lodgement

The AER issues paper notes that customers in other states consuming between 100MWh and 160MWh have access to network tariffs available for small customers. The AER raised concerns that the small customer threshold may not suit some EV charging stations who will be assigned to demand-based tariffs with no ability to opt into an energy-based tariff.[27] Other stakeholders, mainly those representing EV charging stations supported the AER's view requesting tariffs for their business that remove the impact of demand structures.

[27] AER, Ergon Energy and Energex electricity distribution determinations 2025–30, Issues Paper, March 2024, page(s) 51–52.

The RRG were less supportive of tariffs targeted toward EV charging stations. Their concern is that the EV industry proposals lock in an effective cross subsidy for other customers to pay for and this will be hard to change in the future.[28]

The EVC stated that capacity charges beginning at consumption over 100MWh negatively impacts public fast chargers in regional areas as despite relatively low utilisation, as they are faced with capacity charges that are very expensive and get more expensive the higher the demand.[29]

Evie stated that Queensland EV drivers are already facing very high charging costs when using publicly available EV charging sites. Evie submitted that the AER endorsement of Ergon Energy Network tariffs would exacerbate this, of which the negative effects would be felt greatest in regional and rural areas.[30]

Engagement post lodgement

We provided further information to the NPWG outlining a range of potential options available for customers consuming between 100MWh and 160MWh per annum. This was supported by external analysis regarding impacts on EV charging operations under different configurations. This information was also provided to AER staff.

The NPWG supported our preference to avoid concessional tariffs for one industry segment and instead continue to make the cost of network peak augmentation explicit and transparent through demand charges in all SAC Large network tariffs. Our preferred approach is more consistent with the Pricing Principles and promotes better utilisation through incentives for efficient use of network peak capacity.

Further Considerations post Draft Decision

The AER's Draft Decision is to not accept Ergon Energy Network's assignment policies for large customers (LV customers consuming over 100 MWh per annum). Before approving the Revised TSS, the AER expects Ergon Energy Network to offer a TOU option for LV large business customers with demand greater than 120kVA but consumption less than 160MWh.

The AER's justification is based on its own view that a consistent National Electricity Market - wide structure for peaky load business customers, such as EV charge point operators, would further contribute to the achievement of the NEO, noting Queensland's targets for reducing Australia's greenhouse gas emissions.

We provided information to the AER regarding the consequences of introducing this tariff on incentives for efficient use of network peak capacity to improve utilisation. In our view demand based charges during the peak period demonstrably provide a better signal to customers that reflects the potential costs of future investment associated with the demand on the network in the peak window.

The AER's proposed TOU Energy tariff, when compared to the current default tariff, rewards poor utilisation and penalises better utilisation.

Introducing TOU energy tariffs are likely to be attractive to existing SAC Large customers that are making limited use of peak network capacity. "Peaky" load profiles, or those that swing between no load to high load and back in short periods, are difficult to manage from a network perspective and are most likely to trigger additional network costs especially with LV customers accessing up to 1,000kVA. All things being equal, concessional tariffs for "peaky" loads place upward pressure on future expenditure, and prices for other customers compared to more efficient tariffs.

[28] Energy Queensland RRG, Submission on Ergon Energy and Energex electricity distribution regulatory proposals 2025–30 and the Australian Energy Regulator's Issues Paper, May 2024, page 65.
[29] EVC Submission to AER on the Energex regulatory proposal 2025-30, May 2024, page 5.
[30] Evie Networks, Submission by Evie Networks to the Australian Energy Regulator on QLD DNSPs' 2025-2030 Pricing Proposals, May 2024, page 6.

The AER's Draft Decision also departs from previous concerns around the complexity of numerous overlapping tariff structures. Both the AER and stakeholders have previously noted inherent complexity associated with numerous tariffs structures and designs. There are already other options for customers consuming more than 100MWh to reduce pressure on prices, including options for primary and secondary load control tariffs. Alternatively, solar and storage may offer these type of customers better outcomes without the need for additional tariffs.

Outcomes we have included in our Revised TSS

To ensure our TSS will be approved, our Revised TSS incorporates the AERs request to offer a new TOU energy tariff for SAC Large customers with annual consumption between 100 MWh and 160 MWh and demand greater than 120kVa.

5.4.3 Two-way tariff structures, transition and interaction with dynamic connections

Changes to the regulatory framework require us to consider transitioning to incentives through our pricing structures aimed at ensuring that future network investment required to manage exports in the middle of the day is paid for by those causing that investment, therefore minimising non-solar customers subsidising infrastructure investment for export. Pricing structures which achieve this are commonly known as two-way tariff structures as they often include a separate charge and reward component for exports at different times.

The AER's Export Tariff Guidelines require Ergon Energy Network to:

- demonstrate why two-way pricing is justified
- demonstrate how it has developed two-way proposals
- describe its stakeholder engagement strategy, and
- explain how Ergon Energy Network considered the interaction between export tariffs consumption tariffs.

Pre-lodgement engagement and Initial TSS

Our Initial TSS included all relevant information in support of a transition to export tariffs including engagement arrangements we undertook with customers, retailers and other stakeholders.

We investigated a range of options developed by other networks for two-way export tariff structures that best align to our default tariff pricing mechanisms, recognising customer preference for TOU windows. Our engagement with customers included videos and fact sheets with explanations of two-way tariffs and why they are important.

Customers were cautious about implementation of a two-way tariff. While recognising the need for tariffs to keep pace with change, many customers wanted other reforms to settle before making such changes. Given current arrangements are complex in themselves, customers thought change should be gradual and incremental only after all other reforms had been successfully bedded down with appropriate information and education. Optionality was an important factor for many of our customers.

Some retailers also expressed reservations regarding two-way tariffs. In response to our Draft Plan, one retailer did not support any tariffs that imposed penalties for exporting as it penalises customers who have little or no control over their exported energy. Other retailers raised concerns regarding customer education, noting customers would not understand the tariff or why it is being applied. At least one retailer submitted a preference of explaining changes be delegated to networks and government to handle.

Our Initial Tariff Structure Statement (TSS) applied a "medium pace" transition for the introduction of the two-way tariffs. The tariff would apply to new export customers from 2026, as well as making it optional for exporting customers. Assignment to all customers applied from 2028 in line with our commitment to settle other changes first (changing TOU windows).

Additionally, the Initial TSS allowed residential and small business customers with a dynamic connection arrangement (or customers with a new dynamic connection arrangement) to opt-out of any assignment to two-way tariffs. This met customer expectations as to choice between avoiding dynamic curtailment of export but incurring some charge for export at peak times, or saving on charges for export, but allowing some form of curtailment at peak times.

Issues raised post lodgement

The EVC preferred tariff arrangements where peak export rewards were de-linked from export charges including the addition of peak export rewards to prosumers on a flat tariff to incentivise participation and behaviour change.[31]

Origin Energy was concerned that a significant proportion of their customers will exceed the Basic Export Level and incur additional costs and wanted further information on export tariff bill impacts.

Origin Energy highlighted that customers would need education to understand the tariff but suggested it should not be the retailer's responsibility to inform customers on export charging. Instead, the state government and network business should take responsibility.[32]

The AER's Issues Paper appeared to accept the proposed structure and transition approach to two-way tariffs. The AER queried whether additional information such as the cost of the dynamic connection, including who pays for connection, how the arrangements will work in practice and whether the dynamic connection can then be unwound should be part of the TSS or supporting material.[33]

Engagement with NPWG

We engaged with the NPWG on the AER's concerns including providing explanations regarding the cost of the dynamic connection, who pays for connection, how the arrangements will work in practice. We noted that while the AER issue was not about prices or changes to assignment arrangements. However, removing any link between dynamic connections and export tariffs would mean all exporting customers would pay export charges, regardless of their connection arrangement. This would provide less incentive for exporting customers to take up dynamic connections, potentially leading to higher future investment in the network to support more exports.

Importantly, optionality was a condition for customer acceptance of a faster transition to two-way tariffs. Removal of optionality is against customer preferences feedback provided in our pre-submission engagement, where customers told us they wanted choices.

The NPWG was supportive of our position we put forward in July regarding dynamic connections provided we included further explanation in our Revised Explanatory Statement.

AER's Draft Decision

The AER's Draft Decision rejected Ergon Energy Network's two-way tariffs on the basis that they do not comply with all the requirements in the NER. The AER has outlined the following changes that they want included in any Revised TSS before approving:

- changing parameters so the basic export level and export charges are expressed in kWh rather than in kW for small customers
- inclusion of an explicit export tariff transition strategy, and
- inclusion of customer bill impact analysis for LV business customers facing two-way pricing.

---

[31] EVC Submission to AER on the Ergon Energy regulatory proposal 2025-30, May 2024, page 2.
[32] Origin Energy, Origin Energy - Submission - 2025-30 Electricity Determination - Energex, Ergon & SA Power Networks - May 2024_1.pdf (aer.gov.au), (retrieved 31 October 2024).
[33] AER, Ergon Energy and Energex electricity distribution determinations 2025–30, Issues Paper, March 2024, page 51.

The AER also encouraged Ergon Energy Network to include the following:

- Further detail on how 'dynamic connections' work in practice within their export tariff transition strategy.
- An export tariff factsheet (i.e. worked examples, analysis of how customers with different solar PV systems could be impacted).
- More information on the dynamic connection agreement alternative for two-way tariffs (i.e. the cost of the dynamic connection, including who pays for connection, how the arrangements will work in practice and whether the dynamic connection can then be unwound).
- Reference to costs to support excess solar exports to the network.

Faster transition to two-way tariffs no longer justified

We have reflected on the AER's Draft Decision as well as circumstances since the lodgement of our Initial TSS when considering our justification for transitioning toward two-way tariffs. Our Revised TSS now includes an Export Transition Strategy which effectively suspends the introduction of two-way tariffs until the 2030-35 regulatory control period.

Sections 3.1.1 and 5.4.1 above provide detail on a very strong public focus on energy pricing. Significant media attention toward energy pricing and consumer concerns related to smart meter rollout, customer choice, and time variant energy bills being imposed on customers, sometimes without consent. This focus has resulted in government and policy response. The AER has also acknowledged that this has influenced its Draft Decision on tariff structures and assignment arrangements.

Our engagement relating to two-way tariffs did not result in unanimous support. The comfort levels for customers on transitioning to two-way tariffs was not as strong as their comfort for changing TOU windows. Any agreed transition pathway was contingent on ensuring all customers could be brought along with clear information and education. Customers believed this could only happen once other reforms were resolved and embedded. The changes put forward by the AER are significant and need to be embedded, justifying a delay in implementation.

Customers expressed the need for optionality and time to adjust, which is reflected in our transition approach. Customers were also interested in the ability to avoid export charges prompting our introduction on dynamic connections as an opt-out approach.

In the context of other significant changes required by the AER as well broader policy uncertainty around retail tariff application, a delay in implementation is also justified given caveats placed by customers on transitioning to two-way tariffs based on a settled reform environment.

The AER's Draft Decision regarding demand tariffs creates a high hurdle for demand tariffs that needs to be carefully considered in the context of any Revised TSS. When assessing two-way tariffs with the same criteria, we have suggested a more cautious approach to our transition strategy. We have considered the following additional factors in support of a longer transition period:

- The AER's Draft Decision to reject of two-way tariffs, suggesting charging mechanism calculations (including changes to the Basic Export Level) must be modified to be capable of acceptance.
- The AER has not explicitly explained the modifications that are necessary but have requested modifications be made with an expectation that they be finalised and incorporated into engagement material for customers prior to implementation.
- The modifications have therefore not been consulted on with customers or retailers and have not been considered for internal development (through billing).

- Significant changes to the assignment arrangements proposed in the Initial TSS, coinciding with a range of other tariff reforms approved by the AER will place pressure on existing and new systems as well as those of other retailers.
- Information and education for customers is difficult to undertake in an uncertain policy environment. This is particularly the case for regional Queensland under a notified pricing regime.
- Any proposed benefits from export tariffs, when assessed against current risks, uncertainties and future costs do not justify an early transition.

It is clear from other AER decisions and the broader pricing policy context, that several reforms are still being worked through. Most notably, policy changes relating to the smart meter rollout and customer choice in relation to time variant tariffs from a retailer. In such an uncertain policy environment customers' capability to reasonably understand two-way tariffs, and retailers and third parties' ability to incorporate two-way pricing options is greatly diminished.

We have also been influenced by stakeholder feedback on policy uncertainty around energy pricing generally with recent changes announced by the Queensland Government and likely changes by the AEMC in response to customer frustration over retail tariff assignment. On this issue, further time is needed to understand the retail pricing landscape to ensure that consumers are appropriately prepared both with information as well as the means to understand and take advantage of these new innovative tariff arrangements.

Our Initial TSS noted the potential benefits for two-way tariffs over the long-term. However, analysis provided to the AER noted that the impact of two-way tariffs based on our Initial TSS would result in an impact for a customer with a typical solar PV connection of between $10-$15 per annum. To the extent that policy frameworks even allow non-voluntary pass through of export prices, our analysis suggests the quantum of export charges unlikely to be sufficient to occasion any meaningful change in customer behaviour, with minimal benefits in the short term.

While our DER integration strategy did incorporate the value of benefits of price signals with load and generation flexibility, the AER suggested our analysis was somewhat flawed, and overstated the business as usual investment required to maintain the export service. While we stand behind our analysis, any suggested overstatement of network benefits would be true of our "tariff only" intervention option. In light of the AER's position that two-way tariffs do not demonstrate significant value for customers in the next regulatory control period (and any benefits are overstated) any transition before 2030 is less justified. It should also be noted that we have made no changes (that is, not sought to increase) to forecast expenditure to cater for the delay in our two-way tariff transition.

While our DER integration strategy did incorporate the value of benefits of price signals with load and generation flexibility, the AER was quite critical of the supporting analysis, suggesting it was somewhat flawed and overstated business as usual investment required to maintain the export service. We have made no changes to forecast expenditure to cater for the delay in our two-way tariff transition.

Other tariff reforms we have implemented in the next regulatory control period have similar objectives as export tariffs, with potentially even greater effect. These include introduction of new TOU windows as well as tariffs which incentivise grid scale storage and active device management. Unlike many other networks we also have plans in place to manage customer and network impact from exports through with the introduction dynamic connection arrangements for customers. Our tariffs for Ergon Energy Network customers support Energy Queensland's demand flexibility programs which are without peer, with over 1 million participating customers across Queensland enhancing our network management and hosting capacity capabilities.

We also note that the AER accepted Evoenergy's withdrawal of two-way pricing for residential customers in its final decision for the 2024–29 period.[34] In making its decision the AER accepted Evoenergy identified additional costs associated with introducing two-way tariffs would outweigh the benefits for the 2024–29 period.

We engaged with Voice of the Customer panel representatives and the NPWG on our revised approach and received a mixed response. Some customers maintained their scepticism of introducing export tariffs at all, suggesting that the arrangements appear to disincentivise solar uptake and therefore is counter intuitive to the energy transition. Other customers felt that this resulted in a pace of change that was too slow. Most customers found export tariffs complex and questioned why more expenditure wasn't allowed to educate and inform customers on tariff arrangements.

Most NPWG representatives were disappointed in the direction of both the default tariff for residential and small business customers and the decision to delay the introduction of two-way tariffs, suggesting both changes represent a movement away from promoting more efficient tariffs.

As requested by the AER, our Revised TSS will include an explicit Export Charge Transition Strategy with changes that will move any implementation of two-way tariffs until beyond the next TSS period.

5.4.4 Storage tariffs – pricing arrangements and quantum of fixed charge

In response to customer feedback, our Initial TSS introduced storage specific tariffs to cater for customer connections that combine both load and generation characteristics. The tariffs largely replicated storage tariff structures which were offered to customers in Ausgrid's network following positive consultation with customers and which since has been largely accepted by the AER. Ausgrid's proposed tariffs included both import and export elements directly linked to localised and system constraints.

Pre-lodgement engagement and Initial TSS

During consultation on our Draft Plans for tariffs in September 2023, we received strong feedback from some customers wanting better pricing arrangements to support greater levels of storage investment across our network. There were concerns that our existing structures did not fully cater for the unique nature of these investments. Customers encouraged us to view what other network businesses proposed in response to the characteristics of storage customer.

Our Initial TSS included both a Dynamic Price Storage tariff and Dynamic Flex Storage tariff and sought to encapsulate similar characteristics by incorporating both critical peak pricing and flexible load elements.[35]

Issues raised post lodgement

The AER Issues Paper made little comment on the storage tariff. Zero Emissions Noosa raised concerns with the AER in the Issues Paper public forum and formally submitted that storage tariff fixed costs are too high. The high fixed charges and lack of network rebates, in their view, disincentivises community batteries and makes them financially unviable.[36]

[34] AER, Evoenergy Electricity Distribution Determination 2024 to 2029 – Attachment 19 Tariff structure statement, Final Decision, April 2024.

[35] Note the dynamic flex and dynamic price storage tariffs are not to be confused with the LV two-way network tariff operating between 1.5kW and 30kW of Export.

[36] Zero Emissions Noosa, Submission to Australian Energy Regulator re Energex Tariff Structure Statement 2025-2030, Submission, April 2024, page(s) 5–6.

Submissions from Noosa Council,[37] Noosa Biosphere,[38] SEQCRA,[39] Climate Council,[40] Moreton Climate Action Now,[41] Renew Gold Coast Branch[42] and the AER[43] echoed concerns about the application of the proposed storage tariffs and the level of fixed charges.

The RRG supported Ergon Energy Network's proposed tariffs to apply to batteries suggesting that they do not see the role of the network tariffs to subsidise a business case for batteries.

Engagement with NPWG

We discussed with the NPWG the trade-off between lower fixed prices to incentivise higher levels of investment in community batteries and longer term subsidy issues for non-storage customers if lower charges remain embedded in pricing.

The NPWG discussed these issues with a range of stakeholders – including Zero Emissions Noosa. They concluded that battery technology and associated costs are still evolving, with most proponents still relying on some form of subsidy to support their business case. NPWG members were concerned with arrangements which conflict with the Pricing Principles and were focussed toward setting prices that reflect the efficient costs of providing services to all customers.

Nevertheless, there was recognition of the value of storage to the networks and to the extent that lower fixed charges encourage connection of batteries can be transitioned over time and there is evidence that storage connections provide no additional burdens on the network there was some level of acceptance for fixed charge rebalancing.

Further Considerations post AER Draft Decision

Progress from our dynamic storage pricing trials have been quite successful. A customer on our current storage tariff trial provided the following feedback:

> *"Further alignment between tariffs and dynamic operating envelopes will help unlock the opportunities for more distributed storage on the network by reducing connection costs and allowing for alignment between; spot pricing, network constraints and network use charges.*[44]

We were surprised at the AER's Draft Decision to reject Ergon Energy Network's proposed grid-scale storage tariffs, given approval of other networks grid-scale storage tariffs based on equivalent detail provided in their TSS's. The AER appears to have set different expectations for the Queensland network businesses, requiring notice periods, durations, frequency, and triggers for the proposed critical events, and requiring that these should all be included in the TSS before being capable of acceptance. The AER claimed that without this information in the TSS, storage tariffs are not capable of being understood by customers or able to be incorporated into retail offers.

---

[37] Noosa Council, Noosa Council - Submission - 2025-30 Electricity Determination - Energex - May 2024.pdf (aer.gov.au), (retrieved 31 October 2024).

[38] Noosa Biosphere Reserve Foundation, Noosa Biosphere Reserve Foundation - Submission - 2025-30 Electricity Determination - Energex - May 2024.pdf (aer.gov.au), (retrieved 31 October 2024).

[39] Southeast Queensland Climate Resilient Alliance, SEQCRA - Submission - 2025-30 Electricity Determination - Energex - May 2024.pdf (aer.gov.au), (retrieved 31 October 2024).

[40] Climate Council, Climate Council - Submission - 2025-30 Electricity Determination - Energex - May 2024.pdf (aer.gov.au), (retrieved 31 October 2024).

[41] Moreton Climate Action Now campaign, Moreton Climate Action Now campaign - Submission - 2025-30 Electricity Determination - Energex - May 2024.pdf (aer.gov.au), (retrieved 31 October 2024).

[42] Renew Gold Coast Branch, Renew Gold Coast Branch - Submission - 2025-30 Electricity Determination - Energex - May 2024.pdf (aer.gov.au) (retrieved 31 October 2024).

[43] AER, Ergon Energy and Energex Electricity Distribution Determinations 2025 to 2030, Attachment 19 Tariff structure statement, September 2024, page 43.

[44] Innovation and Development Manager, LGI Limited - 1 October 2024.

The AER identified the following further specificity Ergon Energy Network could add in our Revised TSS:

- How the locational element of tariffs will be implemented.
- What criteria would qualify storage for access to the tariffs and to rewards.
- How customers may be notified of critical peak events.
- Whether there is a minimum/maximum number of each type of critical peak event.

Whilst the AER acknowledged the fixed charge implicit in the storage tariff structure was relatively high, the rate was not uniquely high when compared to all other storage tariffs.

Outcomes we have included in our Revised TSS

The Dynamic (Flex) Storage tariff (with no critical peak prices) will be included in the TSS. Availability of our Dynamic (Flex) Storage tariff is conditional on customers entering a dynamic connection agreement, which stipulates network-determined Dynamic Operating Envelopes (DOEs).

The Dynamic Price Storage tariff incorporating critical peak period import and export charge components will be removed from the TSS and included as a trial tariff during the 2025-30 regulatory control period (see Appendix E). In addition, a secondary tariff incorporating critical peak period import and export reward components will be trailed during the 2025-30 regulatory control period (see Appendix E). The secondary tariff will be made available to customers on both the Dynamic Flex and Price Storage tariffs subject to trial conditions.

The trial tariffs will focus on providing price signals for export or import at times of constraint in a way that either encourages avoidance of import or export at the critical event or incentivises import or export at the critical event through rewards. We consider the subsequent enhanced data collection and reporting mechanisms form trialling these tariffs will provide the necessary evidence to demonstrate compliance with the Pricing Principles. The trial will allow for an iterative approach, enabling us to refine the tariff design based on observed outcomes and customer and stakeholder feedback.

We are proposing a contingent trigger to introduce the Dynamic Price Storage tariff and secondary tariff depending on trial outcomes and AER endorsement.

5.4.5 Link between tariff assignment arrangements and connections associated with active device management and load control

In our Initial TSS we retained all existing load control options whist also introducing a new flexible load tariff to cater for a broader range of active device management options. The new flexible load tariff will apply to one or more eligible controlled device appliances connected to the main circuit, rather than through a separately metered and controlled on a secondary circuit. The load control tariffs in our Initial TSS proposal supported the wider customer choice of network connection options on offer in the evolving energy market, allowing customers to benefit through lower prices as well as being able to optimise the use of any on-site solar generation. In return, we would retain the network benefit from being able to manage the existing load control fleet for day-to-day load switching, and emerging key loads (like EV Supply Equipment (EVSE)) for emergency network management response, as required.

Issues raised post lodgement

In its Issues Paper, the AER was of the view that the interactions between tariffs, connections policies and the QECM was not clearly explained in the TSS.[45] However, the focus of the AER's criticism appeared to relate to technical aspects of the QECM. The AER's interpretation of the QECM amounted to Ergon Energy Network's mandatory distributor control on any appliance greater than 20 amps – this would include most home or small business EV chargers.[46] The AER suggested that under the QECM Ergon Energy Network may switch off (or slow down) any customer's EV fast charger without notice with customers unable to override the external control.[47]

The AER made little mention in its Issues Paper regarding charging parameters or tariff structures but nevertheless, sought clarification of the approach.

The EVC[48] and Tesla[49] also took issues with connection arrangements and consider that load control connection arrangements should be optional for customers with EV fast chargers.

The EVC wanted the AER to use its powers to prohibit Ergon Energy Network from implementing import control without consent.[50]

Engagement post lodgement

In April and July 2023 NPWG meetings, together with the NPWG we unpacked the issue of load control. We highlighted the distinction between connection arrangements and tariff assignment. We also articulated the reasons why the AER's characterisation that Ergon Energy Network has mandatory control of fast EV chargers was incorrect.

We gave the NPWG opportunity to engage with stakeholders such as representatives from the EVC who had raised issues with our connections arrangements as well as subject matter experts within Energy Queensland to provide context around our tariff arrangements link to other network strategies.

With further information and context the NPWG members generally understood that the issues regarding connection arrangements could not be addressed through changes in tariff structures and assignment arrangements. There was consensus among NPWG members that the Revised TSS should include more information on the process of establishing a safe compliant physical connection to the network and the second subsequent process of tariff assignment that aligns with the different connection arrangements. While they also agreed that connection arrangements are outside of the scope of the TSS, the NPWG wanted us to explore pricing options which would further encourage uptake of controllable loads to support network management.

Further Considerations post Draft Decision

The AER's Draft Decision is to reject the flexible control tariff for residential and small business customers on the basis that Ergon Energy Network has not adequately described the relationship between the QECM and its TSS. It continues to claim that the QECM results in mandatory distributor led control for customers with EV fast chargers. Whilst not required, the AER has requested additional explanations in the Revised TSS.[51]

---

45 AER, Ergon Energy and Energex electricity distribution determinations 2025–30, Issues Paper, March 2024, page 48.

46 AER, Ergon Energy and Energex electricity distribution determinations 2025–30, Issues Paper, March 2024, page 52.

47 AER, Ergon Energy and Energex electricity distribution determinations 2025–30, Issues Paper, March 2024, page 52.

48 EVC Submission to AER on the Ergon Energy regulatory proposal 2025-30, May 2024, page 2.

49 Tesla, Energex and Ergon Energy Determinations 2025–30, Submission, May 2024, page 2.

50 EVC Submission to AER on the Energex regulatory proposal 2025-30, May 2024, page 2.

51 AER, Ergon Energy and Energex electricity distribution determinations 2025–30, Issues Paper, March 2024. EVC Submission to AER on the Energex regulatory

Outcomes we have included in Revised TSS

We have included further information in our Explanatory Statement regarding our active device management and load control options, including how it links to associated strategies. We provide additional justification for the need to expand our tariff offering to ensure our strategies to manage demand for the long-term benefit of customers can be sustained and that tariff options are available that efficiently price emerging connection arrangements.

In Section 0 and Appendix B we explain the link between the current QECM and relevant tariff options. This addresses both the demarcation and dependency dimensions between the process of establishing a safe compliant physical connection to the network and the second subsequent process of development of the tariff suite that aligns with the different connection arrangements. While network tariffs will flow from the connection arrangements and provide tariffs that support all the connection options, the connection arrangements themselves are outside of the scope of the TSS.

Our Revised TSS includes information regarding tariff assignment rules for customers based on the nature of their choice of connection. It also outlines tariff structures and details of how those tariffs will work. Details regarding connection arrangements for high electricity demand equipment like EVSE, operation of DOEs, the costs of connection and changes to connection arrangements are not specified in the TSS.

In short, we consider the TSS has a focus on tariff assignment and structure arrangements, which once approved will apply until 30 June 2030. Connection arrangements and dynamic operating arrangements have different governance processes and are likely to evolve and change rapidly over the next 5-10 years. These arrangements are outside the remit of the TSS.

To the extent that these arrangements are "locked in" to a TSS, we restrict evolving non-price arrangements, create inconsistencies in governance with non-price arrangements, resulting in an unnecessary need to regularly seek amendment to the TSS through the AER. We consider customer and key stakeholder education is important and acknowledge the need to ensure customers and other stakeholders are clear on arrangements. However, we consider this should not necessarily be through the TSS.

We have provided further description of control arrangements contained within the QECM, including a description on the three types of load control under the QECM and how they interact with tariffs, supply curtailment arrangements and related issues (see Appendix B and C).

The NPWG members accepted changes to volume rates for secondary controlled load tariffs consistent with changes in primary tariffs. There was also appetite by the NPWG members for greater discounting of flexible load tariffs in the first 12 months of the flexible load tariff (only) on the basis that it may encourage take-up and compliance. An approximate discount equal to five years of the current 50 per cent discount was proposed.

When testing these alternative tariff arrangements internally however, technical constraints and operational concerns arose. Billing system constraints close to the end of the current period placed a risk on the tariff being implemented. There was also a preference for the ongoing benefit for load flexibility be retained (rather than providing a benefit for 12 months only) given load flexibility will be required on an ongoing basis.

proposal 2025-30, Submission, May 2024 and Tesla, Energex and Ergon Energy Determinations 2025–30, Submission, May 2024.

5.4.6 Other issues raised by the AER

Streamlining Tariffs

Customers and retailers told us that we should do more to reduce the number of tariffs we have and simplify our tariffs to make it easier to understand what tariffs are designed to do. For example, in relation to our residential and small customers, we currently have several TOU tariffs, each with different pricing windows which makes it difficult for customers to understand the difference between legacy tariffs and newer cost reflective tariffs.

We heard from our SAC Large customers that they prefer a single tariff that applies to all customers as opposed to us making changes to all current SAC tariffs to increase cost reflectivity and simplify tariff assignments policies.

Our engagement with retailers and major customers highlighted that we have highly complicated tariff arrangements for our CAC customers, with a significantly larger number of site-specific charges than any other distribution business. These arrangements create additional administrative burden for retailers, the regulator, our customers, and our business, with no additional gains.

Further, we received feedback from our NPWG supporting our tariff streamlining initiatives and noting the importance of providing education and options for customers.

The AER's Draft Decision for Ergon Energy Network suggested our Revised TSS could be improved by include more supporting information on the proposal to remove a kW option from the optional Demand Small tariff.[52] For the sake of completeness, we have provided information at Section 6.6.

Under legacy arrangements, some Ergon Energy Network customers were assigned to demand based tariffs while on a basic meter as the registers for these basis meters were capable of anytime demand measurement. Policy changes accelerating smart meter rollouts to almost full penetration will result in many of these remaining customers transitioning to default smart meter tariffs. Consistent with our above streamlining theme we have sought to remove basic meter tariffs with demand charges and reassigned remaining customers to a basic meter tariff.

While this results in moving customers to a less cost reflective tariff arrangement, the transition will likely be temporal as these customers will be transitioned to smart meters over the next five years. It is important to note that where a smart meter is incapable of measuring kVA, kW measurements are applied.

Avoided TUOS

The AER requested further information on avoided TUOS arrangements, in response to submissions.

Our Annual Network Tariff Guide addresses avoided TUOS payments and details on eligibility methodology, payment and recovery of Avoided TUOS. With respect to visibility of Avoided TUOS amounts we pay to customers, the estimated and forecast annual Avoided TUOS costs are published in the annual Pricing Proposal. As all eligible Avoided TUOS National Metering Identifiers (NMIs) are classified as CAC, this is effectively by customer group.

Avoided TUOS payment schedules are provided to customers eligible for Avoided TUOS at the end of each financial year. Audited annual Avoided TUOS aggregate amounts are published on the AER's website in Regulatory Information Notices. (See Appendix H for further details).

---

[52] AER, Ergon Energy and Energex Electricity Distribution Determinations 2025 to 2030, Attachment 19 Tariff structure statement, September 2024, page 33.

6 CONSULTATION OUTCOMES: REVISIONS TO OUR TARIFFS

Our Initial TSS outlined the key changes to tariff structures and assignment arrangements that would apply from 1 July 2025. We provided context for these changes based on pre-lodgement engagement and feedback from customers.

This section focusses on the modified changes with the context of post lodgement engagement and in particular the response to the AER's Draft Decision. Chapter 5 summarises engagement post-lodgement, the AER's Draft Decision and our response to key decisions.

The following main changes will apply to our standard tariff offerings for the 2025-30 regulatory control period:

- **Time windows for demand and energy tariffs** to reflect the trade-off between accuracy and simplicity considering feedback from stakeholders and customers.
- **Changes to assignment arrangements for small (residential and small business) customers** in response to the AER's Draft Decision.
- **Changes to assignment arrangements for SAC Large including a new optional tariff** to reflect the AER's Draft Decision.
- **A transition approach for two-way tariffs** in response to the AER's Draft Decision and current uncertainty in the regulatory and policy environment.
- **Storage network tariffs** with modifications based on the AER's Draft Decision to enable directly connected batteries and other energy storage facilities to connect to our network.
- **Load control tariffs** with modifications and additional context in response to the AER's Draft Decision to provide optionality for customers to receive cost savings for providing operational flexibility to help with network reliability.
- **Network tariff streamlining** to make it easier for retailers and market aggregators to respond to or pass through our price signals to our customers.

6.1 Time windows for Demand and Energy tariffs

6.1.1 Changes to time windows from 1 July 2025

The following charging windows will apply to relevant smart meter tariffs applying to SAC Small customers from 1 July 2025:

- A new time window will apply **daily** from 1 July 2025 (representing an off-peak):
  - for residential customers: from 11am – 4pm
  - for small business customers: from 11am – 1pm
- The peak window for small business customers will change to 5pm – 8pm on **weekdays** only.
- The peak window for residential customers will remain at 4pm-9pm and continue to apply **daily**.
- For the new optional demand-only tariffs, customers will face demand charges in peak and shoulder periods using the same time windows.

Changes to small business and large business TOU windows are also consistent with the Initial TSS.[53]

[53] Some differences remain in the legacy CAC 11kV TOU Demand Tariff (NTC7400). Refer Chapter 3 of the TSS.

Details of all our tariff structures can be found in Chapter 3 of our TSS.

6.1.2 Application changes to charging parameters from 1 July 2025

In response to the AER's Draft Decision our indicative charges maintain a level of peak charges for both our TOU energy and demand-based tariffs that signals LRMC having regard to customer impact and capacity to make changes to mitigate charges through usage decisions. We note that the majority of customers do not face the cost reflective network tariff structures in their retail bill and we expect this will continue for the majority of the regulatory control period under current policy settings.

Nevertheless, in response to the AER's Draft Decision, our indicative rates include peak energy charge rates that place greater accountability on retailers should they wish to pass these charges through with additional margin.

We will target zero distribution volume charges in the off-peak window for small customer smart meter tariffs. In addition, indicative prices for our TOU Demand tariff, applies zero distribution charges in the peak pricing window, so residential customers enjoy a zero distribution energy rate daily for 10 hours and small business customers enjoy a zero distribution energy rate for five hours on weekdays.

Further information on our LRMC application can be found in Section 8.3

Details of our tariff structures can be found in Chapter 3 and Appendix A of our TSS. Revised indicative prices will be included in Attachment 9.01.

6.2 Assignment arrangements

6.2.1 Changes to assignment arrangements for small customers

We have applied changes in our TSS assignment arrangements for residential and small business customers in response to the AER's Draft Decision. For small customers we will adopt the modified TOU Energy optional tariff as a default for new customers and new smart meter customers.

Customers assigned to transitional demand tariffs on 30 June 2025 will remain on their existing tariff. The transitional demand tariffs have been renamed to residential and small business TOU Demand and Energy tariffs with additional TOU pricing windows. Any customers on optional demand tariffs (which are being withdrawn) will be reassigned to residential and small business TOU Demand and Energy Tariff.

Customers currently assigned to the optional TOU Energy tariffs on 30 June 2025 will keep this assignment.

6.2.2 Assignment arrangements for new customers and basic meter upgrades

Section 4.2 of the TSS outlines the assignment arrangements for small customers which are summarised below.

- Customers that have their basic accumulation meter replaced due to end-of-life reasons or due to the AEMC rule change implementation (retailer initiated) may remain on the legacy Flat/IBT tariff for a period of 12 months from the end of the financial year in which the meter upgrade occurred. At the end of this grace period, these customers are reassigned to the default tariff.
- Customers that upgrade from a basic accumulation meter to a smart meter at their request (customer initiated), are immediately reassigned from the Flat/Inclining Block Tariff (IBT) to the default tariff.

We have maintained the same arrangements as our Initial TSS for new customers and basic meter upgrades with the only change being that the default tariff for new small customers and existing customers with new smart meters will no longer be the TOU Demand and Energy tariff. From 1 July the default tariff will be the TOU Energy tariff.

Retailers will continue to retain the option they have had throughout the 2025-25 regulatory control period to reassign customers to either the TOU Energy tariff (the default tariff for new and upgrading customers) or the TOU Demand and Energy tariff.

Section 4.2.3 of our TSS provides detail of our assignment arrangement for customers following meter change.

6.2.3 New tariffs and changes to assignment arrangements for large business

Section 4.5 of our TSS includes the structure of a new optional TOU energy tariff. Eligible customers consuming less than 160MWh and with a maximum demand above 120kVA per month may be reassigned from the default tariff to this new tariff upon request.

The AER largely accepted assignment arrangements for our SAC Large customers. Our Revised TSS is therefore largely unamended. From 1 July 2025 we will assign all customers to our default Large TOU Demand and Energy Tariff. The existing Demand Small tariff will remain as an opt-out choice to assist in managing customer impact.

6.3 Two-way tariffs

Revised Transitional Arrangements

In response to the AER's request, our TSS now includes an explicit Export Tariff Transition Strategy (Chapter 6) and provides additional information demonstrating how it is consistent with the NER and the AER's Export Tariff Guidelines. This includes relevant information in support of our decision to suspend implementation of two-way tariffs until the 2030-35 regulatory control period.

Further information regarding two-way tariffs is provided in Section 5 above. This includes our approach to pre-lodgement engagement, and factors influencing our decision to modify our transition arrangements as part of our Revised TSS.

6.4 Storage tariffs

6.4.1 Dynamic Flex Storage tariff

Our Initial TSS provided rationale and justification for the introduction of Dynamic Flex Storage tariffs. In Section 5.4.4 above we outline our engagement post-lodgement, the AER's Draft Decision and our consideration of the AER's Draft Decision in the context of our Revised TSS.

In response to the AER's Draft Decision, the Dynamic Flex Storage tariff structure has been revised to remove critical peak prices. The Dynamic Flex Storage tariff is available for LV and HV connections. The LV version of the tariff is available to SACs. The HV version of the tariff will be available to CACs. Tariff structures are the same for both voltage levels.

Eligibility for the tariff will be based on technical and operational considerations associated with the connection, including:

- the connection demonstrating import from the network for the purpose of exporting back to the network
- customers entering a dynamic connection agreement, which stipulates network-determined DOEs.[54]

[54] Refer to Chapter 6 of our TSS for Eligibility Criteria.

The term “Dynamic Connection Agreement” is used by Ergon Energy Network to refer to any connection arrangements that involve a DOE. This could take the form of:

- a standard or negotiated connection agreement with a baseline zero export limit unless the DOE permits export;
- an Energy Queensland approved dynamic connection standard, or
- any other arrangement agreed between Ergon Energy Network and the customer at the connection.

A Dynamic Connection Agreement allows Ergon Energy Network to offer a customer access to the network that differs from a traditional static “firm” capacity connection. It involves a customer accepting restrictions on its import or exports, in exchange for receiving a reduction in its network bill that reflects the lower network costs (current or expected) associated with a dynamically controlled service.

Recognising the network benefits of load and generation flexibility and the potential for future cost avoidance through the operation of a DOE, Distribution Use of System (DUOS) rates for import and export demand will be initially set to zero.

In response to the AER’s Draft Decision and stakeholder engagement, indicative prices for our DUOS fixed charge for the Dynamic (Flex) Storage tariffs will be aligned in the first year to the fixed charge for the Large TOU Demand and Energy tariff. For consistency we have applied a proportional adjustment to fixed charges in the HV Dynamic (Flex) Storage tariff.

For all storage tariffs, indicative rates apply zero TUOS and Jurisdictional Scheme volume rates to off-peak and shoulder periods. Fixed charges remain consistent with default tariffs.

Our proposed approach links the rates to the on-going suite of standard tariffs and so no longer involves separate calculation. This approach is a starting point, addressing stakeholder and AER feedback with respect to the level of the fixed charges and will be reviewed over time. These tariff rates are attractive with respect to alternative non-storage tariffs.

We consider the Dynamic Flex Storage tariff is flexible enough to accommodate different types of storage customers and scalable to allow expansion as more customers participate.

For more detail about dynamic connections including allocation and application processes see Appendix A, Appendix G for a process map on the dynamic connection agreement and a case study at Appendix G.

6.4.2 Trial storage tariffs

We will trial a Dynamic Price primary tariff and a new Dynamic Reward secondary tariff during the 2025-30 regulatory control period, rather than including these tariffs in our TSS (see Appendix E). However, we have sought to include these tariffs in the TSS through the contingent tariff adjustment process in the event learnings from these trials and further stakeholder consultation warrants inclusion.

The Dynamic Price primary tariff will include the following dynamic charges:

- Critical Peak Period import charge ($/kVA, up to 40 hours per year, 80 half hours), assumed during high network demand periods, to discourage import.
- Critical peak export charge (applied > 1.5kW, $/kW, up to 40 hours per year, 80 half hours), assumed during low network demand periods, to discourage export.

The Dynamic Reward secondary tariff will include the following dynamic charges:

- Critical peak import reward charge ($/kWh), assumed during minimum network demand periods, to encourage import.
- Critical peak export reward charge ($/kWh), assumed during high network demand periods, to encourage export.

6.5 Tariff changes associated with active device management (including load control)

6.5.1 Relationship between the QECM and TSS

The QECM and TSS relate to separate and distinct aspects of Ergon Energy Network's relationship with customers. The QECM focuses on technical standards and guidelines for connecting customers to the electricity network. Where it does specify certain load management requirements, it does not mandate any specific network tariff. The network tariff options, assignment, structures, charging elements and pricing levels are contained in the TSS and/or the Annual Pricing Proposal. The key linkage is for the TSS to ensure that there are appropriate tariffs available to customers that price and support the connection options that are available.

The QECM needs to keep pace with the changing technological environment and take-up of new and emerging customer energy resources. For this reason, it is updated as needed (more often than the five-year time frame of the TSS). It is therefore essential that the process pertaining to the QECM remain separate from the TSS to allow the QECM to evolve during the five-year regulatory control period, noting any changes in the QECM do not impact the overriding tariff requirements (i.e. eligibility) in the TSS or annual Pricing Proposal.

The QECM references the Network Tariff Guide which includes information to assist retailers and customers understand eligibility and operation of tariffs linked to active device management. Changes to the QECM are updated in the Network Tariff Guide as required.

6.5.2 Secondary Load Control tariffs

Our Initial TSS retained existing load control tariff offerings as they continue to share the network value of customers connected to traditional load control with customers and encourage customer retention of the existing load control circuit.

Following engagement on this issue, our Revised TSS establishes indicative prices which set volume charges to zero, while introducing a low fixed charge (to ensure most customers currently on secondary load control tariffs will see a network charge decrease). Lower network charges for controlled load tariffs aim to incentivise some customers to opt-in to or retain these tariffs.

The operational conditions applying to the secondary load control connections are determined independently of the network tariffs. The QECM references that these conditions are included in the annual Network Tariff Guide Appendix B for ease of access by customers and retailers.

6.5.3 Flexible load tariff

Our new residential and small business flexible load tariffs will be offered as a secondary tariff where the customer has agreed to one or more appliances being under DNSP direct or indirect control. The tariff rewards customers via a negative daily fixed charge that effectively offsets some of the daily fixed charge in the primary tariff.

Equipment will be installed upstream of the appliance in accordance with the relevant QECM,[55] and allow management of customer appliances. Unlike connection arrangements enabling access secondary load control tariffs, equipment enabling access flexible load tariffs does not include separate measurement for pricing purposes. Rather, usage and applicable rates of the nominal primary tariff will apply.

Relevant customer and stakeholder education will ensure the purpose and application of these tariffs, including supply interruptions are well understood by customers. Ergon Energy Network successfully rolled out of non-domestic load control tariffs in the 2020-25 regulatory control period using multiple means to educate customers, including detailed web page content to explain the tariff, eligibility and conditions.[56] We will use learnings from the current period education when rolling out flexible load tariff education.

Update to QECM to facilitate new flexible load tariff

The QECM was updated in February 2024, which expanded the active device management options available, including new options to allow for these devices to be connected to any eligible primary tariff for the NMI (these devices were previously nominally restricted to utilising one of the existing secondary load control tariffs). These changes were in response to increased installation of consumer energy resources like EVSE's and the desire for customers to be able to utilise their own solar generation which is metered separately to the secondary load control tariffs.

In relation to managing customers loads, the active device management options are:

- A network owned device – using audio frequency load control (AFLC) in a ON/OFF control approach (this is the existing / legacy load control management system).
- A dynamic connection – allowing for ramp up / ramp down management of customer equipment (a recently implemented capability that involves publishing of variable dynamic operating envelope (DOE) settings by the DNSP for the customer device which is enabled directly or indirectly via the CSIP-AUS protocol).

In response to the AER's request for further information to be provided on QECM and load control arrangements:

- Appendix B provides further information on the QECM and its relationship with the TSS.
- Appendix C responds to specific questions from the AER in its Draft Decision.
- Appendix D provides additional information on the Flexible Load Tariff.

[55] may include appliance timers.

[56] For example see - https://www.ergon.com.au/loadcontroltariffs.

6.6 Network tariff streamlining

Our Initial TSS outlined our pre-lodgement engagement outcomes, supporting more streamlined tariff arrangements for all customer groups. While largely supported the changes, the AER requested that we provide additional explanation on changes to some SAC Large Tariffs which we have provided in chapter 5.

Our Revised TSS reflects the following streamlining of tariffs:

- Simplify the structure of our small business TOU Energy tariff. This tariff currently has five inclining fixed charge blocks. A customer is assigned to one of the five blocks depending on their annual electricity consumption. Our Revised TSS simplifies this tariff by removing the top four bands. This will also align this tariff structure with the residential version of the TOU Energy tariff.
- Simplifying the structure of our legacy residential and small business IBT, with the three-tiered volume charges replaced by a flat charge. This will increase transparency for customers and ultimately assist with transition to cost-reflective tariffs.
- Withdraw our small business Wide Inclining Fixed tariff (WIFT). This basic meter tariff has a complicated structure with five inclining blocks. We believe that reassigning customers from this tariff to the Flat tariff will improve bill transparency for customers. This will also align our tariff assignment policies for basic meter small business customers with the residential customer tariff assignment approach.
- Rationalise our residential and small business customer tariff offering by closing our optional demand tariffs which have few customers assigned to them.
- Withdraw our optional Demand Medium, Demand Large and Seasonal TOU Demand tariffs. This is our preferred alternative to modifying these legacy SAC Large tariffs to reflect new pricing windows and is consistent with customer and retailer preferences to reduce the complexity and number of tariffs.
- Withdraw our Seasonal TOU Demand 11 or 22kV Bus, Seasonal TOU Demand 11 or 22kV Line, Seasonal TOU Demand 33 or 66kV CAC tariffs.
- Withdraw our Small Business Transitional Network TOU Energy Tariffs 1, 2 and 3 from 1 July 2026.

Table 8 and Table 9 list the tariffs we will permanently close from 1 July 2025. The numbers of customers currently assigned to each tariff is also provided below. Further information about indicative bill impacts for affected customers is provided in Chapter 7.

Table 8: Residential and small business tariffs that will permanently close from 1 July 2025

Tariff name	Number of customers affected	Re-assigned to
Residential Demand (NTC RDEM)	191	Residential Demand & Energy (NTC RTDEM) on 1 July 2025
Small Business Demand (NTC BDEM)	316	Small Business Demand & Energy (NTC BTDEM) on 1 July 2025
WIFT (NTC WIFT)	10,480	Small Business Flat (NTC BIB) first meter read post 1 July 2025
Transitional Network TOU Energy Tariff 1 (NTC BFRM)	-	Small Business TOU Energy (NTC BTOUE) on 1 July 2026
Transitional Network TOU Energy Tariff 2 (NTC BIRR)	-	Small Business TOU Energy (NTC BTOUE) on 1 July 2026
Transitional Network TOU Energy Tariff 3 (NTC BPMP)	-	Small Business TOU Energy (NTC BTOUE) on 1 July 2026

Table 9: Medium and large business tariffs that will permanently close from 1 July 2025

Tariff name	Number of customers affected	Re-assigned to
Large Residential Energy (NTC REST)	-	Residential Flat (NTC RIB) first meter read post 1 July 2025
Demand Medium (NTC DMT)	1,107	LV TOU Demand (NTC LTOUD) or Large Business Basic (BEST), depending on meter type, on 1 July 2025
Demand Large (NTC DLT)	191	LV TOU Demand (NTC LTOUD) on 1 July 2025
SAC Seasonal TOU Demand (NTC STOUD)	419	LV TOU Demand (NTC LTOUD) on 1 July 2025
Seasonal TOU Demand 11 or 22kV Bus (NTC C22BTOUT)	-	C22B on 1 July 2025
Seasonal TOU Demand 11 or 22kV Line (NTC C22LTOUT)	2	C22L on 1 July 2025
Seasonal TOU Demand 33 or 66kV (NTC C66TOUT)	2	C66 on 1 July 2025

7 NETWORK BILL OUTCOMES FOR CUSTOMERS

7.1 Overview

Customers have emphasised the importance of understanding the impact of changing tariff structures on individual bills. We note that given the increasing divergence in the ways customers source and use energy, analysing average or even typical customer bill movements may not provide a full picture of the range of impacts that may result from changes in structure.

Given the substantial changes to a range of tariffs, a separate comprehensive document (Ergon - 9.02 - Network Bill Impacts - January 2024 - public) was prepared with our Initial TSS submission to assist customers and the AER understand network bill impacts associated with:

- changes in revenue across all years for default tariffs
- movement between default and optional tariffs within the same tariff class, and
- movement to default tariffs as a result of a tariff being withdrawn.

We provided a range of impact assessments based on:

- impacts based on a large sample size using all available information
- segment based impacts for some customer classes, and
- persona based impacts for some customer classes.

The below sections provide updates to customer bill impacts based on our Revised TSS and Indicative Network Price List. Updated impacts reflect the latest revenue projections, our approved 2024-25 network prices and changes to tariff assignments in line with the AER's Draft Decision.

7.2 Network bill impacts

We have modelled the annual network bill outcomes across different customer segments based on their 2023 calendar year energy consumption and demand data. For HV customers as well as residential and small business customers our analysis is based on all available smart meter data for the 2023 calendar year. For large LV SAC Large customer bill impact analysis, we used sample data for the 2023 calendar year.

Our analysis assumes no change in behaviour associated with tariff structure reassignment. To the extent that customers respond to price signals, this will likely change their network bill impact.

To minimise complexity, the network bill impact calculations presented in this section only include DUOS charges. We note that the full network charges customers will see also include the pass through of transmission and jurisdiction scheme costs and from 1 July 2025 will also include legacy metering service charges. These charges have not been included in the analysis below.

Further information including customer bill impacts associated with legacy metering charges are discussed in the metering chapter of our Revised Regulatory Proposal.

Our network charges reflect what we charge electricity retailers in regional Queensland, including Ergon Energy Retail. These costs reflect the true costs of distributing electricity in regional Queensland. The Queensland Government establishes notified prices in regional Queensland, including the application of a subsidy. This subsidy recognises that it costs more to supply electricity in regional Queensland compared to the Southeast due to the large geographic supply area and lower population.

Notified retail prices for small customers in Ergon Energy Network's area set by the Queensland Competition Authority based on the cost of supply in Southeast Queensland. For large customers notified prices are based on the Ergon Energy Network pricing zone with the lowest cost of supply (region East).

Taking into account these considerations, the customer bill impacts presented in this chapter are based on the prices in Ergon Energy Network zone East customers which is charged to the retailer.

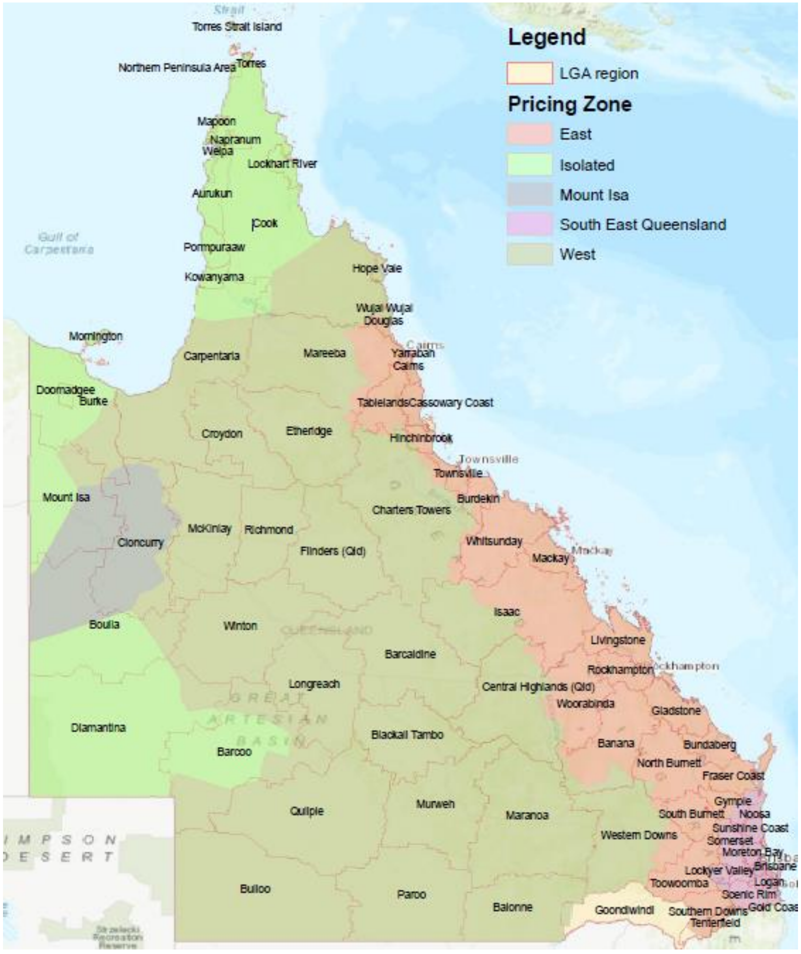
7.2.1 Pricing simplification

Ergon Energy Network pricing arrangements

Three pricing zones have been delineated in the Ergon Energy Network distribution area, broadly based on Queensland's local government areas, cost of supply and legacy arrangements. These designated pricing zones impact the distribution component of the network charges only (transmission charges and jurisdictional scheme charges are not impacted by pricing zones as these costs are passed on equally across all distribution regions). This delineation in distribution regions essentially meant that all our network tariffs (and tariffs structures) are replicated three times, with different prices set for each region.

The distribution pricing zones are shown in Figure 4.

Figure 4: Distribution pricing zones



Regional Queensland retail pricing arrangements

Our network charges reflect what we charge electricity retailers in regional Queensland, including Ergon Energy Retail. These costs reflect the true costs of distributing electricity in regional Queensland. At the retail level, there is limited competition in regional Queensland. The majority of LV consumers are supplied by Ergon Energy Retail under regulated retail prices. Regulated retail prices are set annually by the Queensland Competition Authority.

For small customers (SAC Small) regulated retail prices are based on the cost of supply in South East Queensland (i.e. Energex network). For large LV SAC Large customers regulated retail prices are based on the Ergon Energy Network pricing zones with the lowest cost of supply (pricing zone East).

The Queensland Government's uniform tariff policy ensures the difference between Ergon Energy Network and Energex prices is subsidised at the retail level.

Figure 5 summarises the relationship between network prices in Ergon Energy Network's distribution pricing zones and regulated retail prices in regional Queensland.

Figure 5: Network prices reflected in regulated regional Queensland prices

Customer segment	East pricing region	West pricing region	Mt Isa pricing region
Residential	Energex	Energex	Energex
Small Business	Energex	Energex	Energex
Large low voltage	Ergon Energy Network East Zone	Ergon Energy Network East Zone	Ergon Energy Network East Zone
High voltage	Ergon Energy Network East Zone	Ergon Energy Network East Zone	N/A
Sub-transmission	Ergon Energy Network East Zone	Ergon Energy Network West Zone	N/A

Distribution pricing simplification

Since 2020 we have progressively aligned network tariffs, tariff structures and tariff assignment procedures across Energex and Ergon Energy Network. From 1 July 2025 the tariff structures for residential and small business customers will be fully aligned across the two networks.

When setting retail prices in regional Queensland, Energex prices effectively apply to small customers in Ergon Energy Network's distribution area. The AER's Draft Decision approved simplified and streamlined tariff structures for both Energex and Ergon Energy Network. This will further simplify regulated retail pricing arrangements and increase transparency for customers and retailers.

Our Revised TSS seeks to build on this by aligning charging components for some tariffs. From 1 July 2025, we will align DUOS volume and demand charges across the two networks for small customers with any residual revenue rebalanced through the fixed charge. For our SAC Large customers, we will align the DUOS volume and demand charges across the three pricing zones. We will modify the fixed charges to ensure the proportional revenue recovery in each pricing zone remains unchanged.

Importantly, the alignment of charging components will not impact any customers in regional Queensland on regulated retail tariffs. A small number of customers on market retail tariffs will be impacted. However, the majority of these customers are in the East pricing zone (approximately 8,000 or 1 per cent) and the impact is immaterial based on our analysis. There are less than 150 customers in the West zone and no customers in the Mount Isa zone on market retail tariffs.

The progressive alignment and increase in linkages between the network and retail pricing for regional Queensland is summarised in Table 10.

Table 10: Alignment between network and retail pricing arrangements

Regulatory control period	Network tariff structure	Distribution prices	Regulated retail prices
2015 to 2020	Different for Ergon Energy Network and Energex	Different for Ergon Energy Network and Energex	Reflect Energex network for small customers
2020 to 2025	Partial alignment to Energex	Different for Ergon Energy Network and Energex	Reflect Energex network for small customers
2025 to 2030	Fully aligned to Energex for small customers Majority of tariffs aligned for large customers	Volume and demand prices aligned to Energex for small customers - differences in network revenue reflected in fixed prices	Reflect Energex network for small customers

Bill impacts presented in this section for SAC customers reflect the new pricing arrangements. While distribution bill impacts for residential and small business tariffs are not uniform across the tariff suite, the outcomes are due to revenue rebalancing across the different charging components. These impacts are not expected to be seen by end customers, who will continue to see the Energex network prices passed through in the regulated retail bill.

7.2.2 Residential customers

Table 11 shows the network bill impacts for residential customers who will remain on their existing tariffs in the 2025–26 financial year and for customers who may change tariffs in the 2025–26 financial year. Impacts reflect changes in revenue as well as forecast quantities (i.e. energy consumption, customer numbers and demand). For the TOU Demand and Energy tariff (previously known as Transitional Demand tariff), impacts also reflect tariff structure changes.

During the 2020-25 regulatory control period our TOU Demand and Energy tariff prices have been set to create a small incentive for customers to move to this tariff. As more customers have now moved to this cost-reflective tariff, we are progressively increasing the amount of revenue allocated to this tariff to help avoid bill impact for customers who remain on the flat tariff as part of a diminishing customer base. This revenue rebalancing is reflected in the impact below.

Table 11: Default and optional tariffs continuing into 2025-30

Scenario FY25 to FY26	Portion of customers with bill decrease	Portion of customers with bill increase			Median impact
		<10%	>10% and <20%	>20%	DUOS change (%)
Impacts for customers not changing tariffs					
Flat [57]	11%	27%	31%	31%	13.7%
TOU Energy	0%	15%	45%	39%	17.6%
TOU Demand & Energy	24%	47%	28%	1%	6.2%
Impacts for customer changing tariffs					
Flat to TOU Energy	24%	27%	29%	20%	9.7%
TOU Energy to TOU Demand & Energy	23%	29%	30%	18%	9.4%
TOU Demand & Energy to TOU Energy	2%	26%	53%	19%	13.9%

Network bill mitigation strategies will vary depending on the underlying tariff the customer is on and the extent to which the structure of this tariff is passed through to the end customer.

To the extent TOU windows are passed through to the end customer, bill impacts can be improved by reducing total energy during the peak window (TOU Energy) or minimising demand in the peak window (TOU Demand and Energy). Customers who remain on anytime energy structures mitigate impact by reducing energy use at any time.

Our analysis suggests self-generation (solar and batteries) is a successful mitigation strategy for both anytime and TOU Energy structures. TOU Demand and Energy tariffs do not allow solar customers as much opportunity to avoid network charges. However, benefits for customers on TOU Demand and Energy tariffs are greater when the customer's demand at network peak times is smoothed or shifted across other times.

Customers or retailers may benefit from the alternative primary tariff options in order to reduce network bill impact. Alternatively residential customers may look to changing connection arrangements for discretionary loads to access cheaper rates in return for active device management.

Table 12 shows the 2025–26 financial year network bill impacts for customers who will be reassigned from a tariff we will withdraw at the end of the current TSS period. These impacts are only applicable to customers currently assigned to the tariffs to be withdrawn.

Table 12: Withdrawn tariffs

Scenario FY25 to FY26	Portion of customers with bill decrease	Portion of customers with bill increase			Median impact
		<10%	>10% and <20%	>20%	DUOS change (%)
Residential Demand to TOU Demand & Energy	33%	67%	0%	0%	1.7%

[57] Tariff previously called Residential Inclining Block.

7.2.3 Small business customers

Table 13 shows network bill impacts for small business customers who will remain on their existing tariffs in 2025–26 financial year and for customers who may change tariffs in 2025–26 financial year.

Analysis of the annual impact from DUOS changes for small business customers shows significant variance in outcomes for customers for TOU Energy & Demand tariff (previously known as Transitional Demand tariff), due to tariff structure changes. Bill impact for the Flat tariff reflect the movements in revenue and quantities.

For TOU Energy tariff, which will become our default tariff from 1 July 2025, rebalancing of residual revenue was required to ensure this tariff is more closely aligned with our TOU Demand and Energy tariff. This will help avoid bill impacts for customers changing metering and moving across from the Flat tariff.

Table 13: Default and optional tariffs continuing into 2025-30

Scenario FY25 to FY26	Portion of customers with bill decrease	Portion of customers with bill increase			Median impact
		<10%	>10% and <20%	>20%	DUOS change (%)
Impacts for customers not changing tariffs					
Flat [58]	50%	10%	8%	32%	0.1%
TOU Energy	22%	13%	12%	53%	23.0%
TOU Demand & Energy	13%	19%	20%	48%	19.0%
Impacts for customers changing tariffs					
Flat to TOU Energy	51%	10%	8%	32%	-0.6%
TOU Energy to TOU Demand & Energy	31%	13%	12%	44%	15.7%
TOU Demand & Energy to TOU Energy	6%	12%	18%	64%	27.7%

Network bill mitigation strategies will vary depending on the underlying tariff the customer is on and the extent to which the structure of this tariff is passed through to the end customer.

To the extent TOU windows are passed through to the end customer, bill impacts can be improved by reducing total energy during the peak window (TOU Energy) or minimising demand in the peak window (TOU Demand and Energy). Customers who remain on anytime energy structures mitigate impact by reducing energy use at any time.

Our analysis suggests self-generation (solar and batteries) is a successful mitigation strategy for both anytime and TOU Energy structures. TOU Demand and Energy tariffs do not allow solar customers as much opportunity to avoid network charges. However, benefits for customers on TOU Demand and Energy tariffs are greater when the customer's demand at network peak times is smoothed or shifted across other times.

Customers or retailers may benefit from the alternative primary tariff options in order to reduce network bill impacts. Alternatively, small business customers may look to change connection

[58] Tariff previously called Small Business Inclining Block.

arrangements for discretionary loads to access cheaper network prices in return for active device management.

Table 14 shows the 2025–26 financial year network bill impacts for customers who will be reassigned from a tariff we will withdraw at the end of the current TSS period. These impacts are only applicable to customers currently assigned to the tariffs to be withdrawn.

Majority of tariffs we propose to withdraw have been closed to new customers since 2020 and priced at a premium relative to our default tariffs, therefore a large number of customers who will be reassigned from these tariffs are expected to see a network bill decrease as a result of the reassignment.

Table 14: Withdrawn tariffs

Scenario FY25 to FY26	Portion of customers with bill decrease	Portion of customers with bill increase			Median impact
		<10%	>10% and <20%	>20%	DUOS change (%)
WIFT to Flat	36%	9%	8%	47%	16.1%
Small Business Demand to TOU Demand & Energy	40%	26%	16%	18%	3.3%

7.2.4 SAC Large customers

From 1 July 2025 all smart meter large LV customers will be reassigned to the default Large TOU Demand and Energy tariff. This includes reassignment of customers from Demand Small tariff (which will continue into 2025-30) and other legacy tariffs which will be withdrawn on 1 July 2025 (see Table 15 and Table 19 for network bill impacts).

We have continued the optional Demand Small legacy tariff into the 2025-30 regulatory control period to manage customer impact. Customers assigned to the Large TOU Demand and Energy tariff may be re-assigned to the Demand Small tariff upon application.

Basic meter customers with a demand register who are currently assigned to the Demand Small tariff will be reassigned to the default tariff for basic meter customers, the Large Business Energy tariff. These customers will not be able to opt-in back to the Demand Small tariff unless they upgrade to a smart meter. We have analysed the impact for these customers and found that a majority of customers are expected to see a network bill decrease as a result of the reassignment.

Table 15: Default and optional tariffs continuing into 2025-30

Scenario FY25 to FY26	Portion of customers with bill decrease	Portion of customers with bill increase			Median impact
		<10%	>10% and <20%	>20%	DUOS change (%)
Impacts for customers not changing tariffs					
Large TOU Demand & Energy	59%	15%	21%	5%	-10.3%
Large Business Energy	99%	1%	0%	0%	-55.8%
Impacts for customers changing tariffs					
Demand Small to Large TOU Demand & Energy	22%	19%	45%	14%	12.9%

Network bill impacts for customers seeking access to the new Large TOU Energy tariff (based on identified eligible customers) are shown in Table 16 This new tariff will be available from 1 July 2025. Impacts are only applicable to customers that meet the tariff eligibility criteria (i.e. consumption below 160MWh and demand greater than 120kVA).

Table 16: New optional tariff for 2025-30

Scenario FY25 to FY26	Portion of customers with bill decrease	Portion of customers with bill increase			Median impact
		<10%	>10% and <20%	>20%	DUOS change (%)
Current Tariff* to Large TOU Energy	98%	2%	0%	0%	-28.9%

*Current network tariffs include Demand Large, Demand Small, Demand Medium, Seasonal TOU Demand and Large TOU Demand & Energy.

Options for customers to manage network bill impacts

We have continued the Demand Small legacy tariff into the 2025-30 regulatory control period to manage customer impact. Customers assigned to the Large TOU Demand and Energy tariff may be re-assigned to the Demand Small tariff upon application.

We have analysed the impact of customers with a network bill increase greater than 10 per cent when moving from either Demand Small tariff or withdrawn tariffs to the default tariff in 2025-26. All of these customers will be able to reduce their bill impact should they opt out to the Demand Small tariff (see Table 17).

Table 17: Analysis of customers with bill impact >10% because of reassignment to default tariff, if they chose to opt to Demand Small

Scenario FY26 to FY26	Portion of customers with bill decrease	Portion of customers with bill increase			Median impact
		<10%	>10% and <20%	>20%	DUOS change (%)
Large TOU Demand & Energy to Demand Small	100%	810%	0%	0%	-10.2%

Table 18 shows the combined impact of all of customers either remaining on the default tariff or, for those customers impacted by more than 10 per cent, the impact of their assignment to the Demand Small tariff (in other words the impact of the lower priced tariff option assuming no change in behaviour). Analysis shows that if all customers chose the lower priced tariff option, the majority customers would see either a bill reduction or a small bill increase.

Providing customers with tariff choice helps to avoid bill impacts for those customers who are not able to take advantage of our new lower priced off-peak TOU windows.

Table 18: Network impact assuming most optimal tariff assignment

Scenario FY25 to FY26	Portion of customers with bill decrease	Portion of customers with bill increase			Median impact
		<10%	>10% and <20%	>20%	DUOS change (%)
Current Tariff to Large TOU Demand & Energy or Demand Small	35%	64%	1%	0%	4.4%

Withdrawn tariffs

Table 19 shows the network bill impacts for customers reassigned as a result of their tariff being withdrawn. These impacts are only applicable to customers currently assigned to the tariffs to be withdrawn.

We note that there are currently no customers on the Large Residential Energy tariff which will be withdrawn from 1 July 2025, therefore a network bill impact assessment has not been provided.

Table 19: Withdrawn tariffs

Scenario FY25 to FY26	Portion of customers with bill decrease	Portion of customers with bill increase			Median impact
		<10%	>10% and <20%	>20%	DUOS change (%)
Demand Large to Large TOU Demand & Energy	31%	8%	16%	46%	16.6%
Demand Medium to Large TOU Demand & Energy	42%	29%	28%	1%	3.4%
Seasonal TOU Demand to Large TOU Demand & Energy	82%	11%	3%	4%	-11.8%

7.2.5 High Voltage customers

Table 20 shows the network bill impacts for CAC and ICC customers on the default tariffs.

There have been no structural changes to tariffs in the ICC tariff class. The movement in customer impacts is consistent with revenue changes.

Table 20: Default and optional tariffs continuing into 2025-30

Scenario FY25 to FY26	Portion of customers with bill decrease	Portion of customers with bill increase			Median impact
		<10%	>10% and <20%	>20%	DUOS change (%)
Impacts for customers not changing tariffs					
CAC 22/11kV kV Line	15%	68%	16%	1%	7.2%
CAC 22/11kV Bus	23%	19%	42%	16%	10.2%
CAC 33 kV	31%	31%	31%	8%	4.4%
CAC 66kV	3%	26%	58%	8%	11.9%
ICC	1%	98%	0%	1%	7.8%

We have introduced new optional tariffs which provide HV customers with stronger price signals based on similar TOU windows to other tariff classes. Table 21 shows network bill impacts for customers seeking to opt-in to the new CAC HV Bus or Line TOU Demand tariffs. Our analysis suggests that some customers can mitigate impacts from price changes through reassignment to the optional tariff. To the extent that some customers are able to respond to price signals, the number of customers benefiting from reassignment will increase.

Table 21: New optional tariffs for 2025-30

Scenario FY25 to FY26	Portion of customers with bill decrease	Portion of customers with bill increase			Median impact
		<10%	>10% and <20%	>20%	DUOS change (%)
Impacts for customers changing tariffs					
CAC 22/11kV Line to HV Line TOU Demand	42%	12%	25%	20%	4.6%
CAC 22/11kV Bus to HV Bus TOU Demand	23%	6%	16%	55%	24.4%
CAC 33kV to CAC 33kV TOU Demand	69%	0%	0%	31%	-20.4%
CAC 66kV to CAC 66kV TOU Demand	29%	23%	10%	39%	9.2%

CAC seasonal tariffs will be withdrawn on 1 July 2025 and customers reassigned to the default tariffs. As there are currently only six customers assigned to the CAC seasonal tariffs, we have modelled the network bill impacts for each customer. Based on the indicative DUOS prices and estimated quantities, and the average impact customer impact from reassignment to the default CAC tariff is an increase in network bill charges of 1.1 per cent in 2025-26 compared with 2024-25.

ICC customer impacts reflect the increases in revenue.

7.3 Long-term benefits for consumers

At the recommendation of our NPWG we sought to project the long-term impacts of tariff changes and dynamic controls on customers.

We asked Dynamic Analysis to look at future expenditure and revenue outcomes as well as bill impacts based on "book-end scenarios" to understand the individual and economic benefits that may be associated with transitioning to more efficient tariffs - with and without controls on load and generation.

Dynamic Analysis constructed three "bookend" scenarios for Ergon Energy Network from the 2029-2030 financial year (the last year of the upcoming regulatory control period) to 2049-2050 financial year:

- Scenario 1 – From the 2029-30 financial year to the 2049-50 financial year, all customers would not be subject to "time variable" import tariffs (i.e.: they would be on a fixed/energy volume tariff) and no export tariffs would apply. There would also be no application of controls on any appliances.
- Scenario 2 – From the 2029-30 financial year to the 2049-50 financial year, all customers would be on tariff structures consistent with the demand and export tariffs outlined in this TSS. However, there would be no dynamic controls of consumer energy resource (CER) or appliances.
- Scenario 3 – Dynamic controls would complement tariff changes and be applied to customer energy resources and controllable appliances such as EV's.

For both Energex and Ergon Energy Network, the modelling suggests that capital (capex) and operating expenditure (opex) would likely be significantly higher under Scenario 1 where no "time variable tariffs", export tariffs or dynamic controls are applied. Scenario 2 would result in significantly lower capex and opex than Scenario 1. Scenario 3 would result in the lowest expenditure.

The key driver of the results is the relative difference in peak demand capex across the scenarios.

Higher peak demand growth is likely if customers are not provided with tariff incentives to shift demand to off-peak periods. In particular, most recent data shows that EVs are likely to be disproportionately charged in the evening peak if customers are provided with no incentives to shift charging times.

Higher peak demand results in more investment in augmenting (new infrastructure) the network under Scenario 1. Under Scenario 2, customers respond to the peak demand signal by shifting a significant amount of load to off-peak periods, lowering investment in new infrastructure. The key finding was that if customers shifted a small proportion of their load during the peak time, they would likely share in the benefits.

7.4 Managing tariff changes

Our changes are driven by the need to ensure our tariffs structures are supporting the current and future changes in how customers source and use energy. Providing efficient signals though our prices ensures that customers have better information as to how they use the network, providing fairer outcomes to all customers and the potential for lower investment in future years.

Our pricing strategies are interlinked with a range of other strategies to allow customers more opportunities to adopt greater levels of distributed energy resources, more technology (such as EVs) and more flexibility to reduce their energy bills. We've expanded our use of flexible tariffs to provide greater levels of support for those customers that are unable to adopt load shift practices.

We do acknowledge that there are risks associated with changes to our network tariffs, the need to adopt a smart meter to access many of the opportunities, the way retailers pass through our structures and rapidly evolving customer technology that may present in the latter part of the regulatory control period. We have attempted to mitigate these impacts through greater levels of customer education, contingency change factors and notifying Government of potential issues.

8 COMPLIANCE WITH PRICING PRINCIPLES

8.1 Overview of Pricing Principles

This section supports our TSS Chapter 5 in outlining how we developed our tariffs and how our proposal satisfies the NER Pricing Principles.

Clause 6.18.1A(b) of the NER requires that a TSS must comply with the Pricing Principles which are set out in clause 6.18.5 of the NER. The Pricing Principles require that:

- the revenue to be recovered must lie between an upper bound (stand alone cost) and a lower bound (avoidable cost) (clause 6.18.5(e))
- tariffs must be based on the LRMC of providing the service to which it relates to the retail customers assigned to the tariff (clause 6.18.5(f))
- tariffs must be designed to recover revenue in a way that minimises distortions to the price signals, efficient costs of serving the retail customers that are assigned to the tariffs (clause 6.18.5(g))
- we must consider retail customer impact associated with changes in tariffs from the previous year and may reasonably vary from compliance with other Pricing Principles to the extent necessary to mitigate the impact of changes (clause 6.18.5(h))
- the structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to the type and nature of those customers, and feedback resulting from the engagement with customers (clause 6.18.5(i)), and
- a tariff must comply with the NER and all applicable regulatory instruments (clause 6.18.5(j)).

These are discussed in our TSS with further information provided below.

8.2 Stand alone and avoidable costs methodology

The NER requires the revenues recovered from each tariff class to be within a band that is:

- less than the standalone cost of providing network services to that tariff class, and
- at least equal to the avoidable cost of providing network services to that tariff class.

The upper and lower bands provide useful guardrails for each tariff class and to ensure that there are no inefficient economic cross-subsidies contained within the tariff classes for the following reasons:

- **Avoidable cost**: If customers were to be charged below the avoidable cost, it would be economically beneficial to stop supplying the customers as the associated costs would exceed the revenue obtained from the customer.
- **Stand alone cost**: If customers were to pay above the stand-alone cost, then it may be beneficial for customers to switch to an alternative service arrangement creating the possibility of inefficient bypass of the existing infrastructure.

Our stand-alone and avoidable cost estimates are prepared using building block costs from the post-tax revenue model. The avoidable costs include scalable operating costs for assets and customer services. Stand-alone costs also include the indirect component for operating costs and the return on capex. We derive standalone and avoidable cost boundaries for each tariff class in line with the methodologies applied by other DNSPs which largely involves the following steps:

Avoidable costs

1. Collate relevant operating and capital costs associated with standard control services.
2. Determine the proportion of different operating and capital expense categories that would be avoidable.
3. Assign what percentage of these avoidable costs are allocated based on different measures (i.e. those allocated on a customer or energy related basis).
4. Sum all categories for each customer class using relevant weights for the number of customers and energy consumption.

The equation below provides a graphical description of the methodology:

Equation 1

$$Avoidable\ cost_{ct} = customer\ related\ costs_t * \frac{\frac{Customer\ numbers_{ct}}{Total\ customer\ numbers_t}}{Total\ building\ block\ cost_t} + energy\ related\ costs * \frac{\frac{Energy_{ct}}{Total\ energy_t}}{Total\ building\ cost_t}$$

Standalone costs

1. Collate relevant operating and capital costs associated with standard control services.
2. Determine if the cost is either scalable - meaning that cost varies with the number of customers or energy consumed, or non-scalable - where the cost is fixed and does not vary with customer numbers or consumption.
3. Calculate standalone costs, which are a function of avoidable costs (those that depend on a customer class), scalable indirect costs and non-scalable indirect costs.

The equation provides a graphical description of the methodology:

Equation 2

$$Standalone\ cost_{ct} = avoidable\ cost_{ct} + \frac{Non-scalable\ costs_t + (Scalable\ costs_t * Proportion\ of\ scalable\ costs)}{Total\ building\ cost_t}$$

Where c denotes customer class and t denotes year.

Our TSS (Section 5.1) demonstrates the distribution revenue in 2025-26 for each tariff class falls between the stand alone and avoidable cost boundaries.

8.3 Long Run Marginal Cost estimation approach

8.3.1 Overview

Efficient tariffs are based on the LRMC of providing the service to customers assigned to that tariff.

The Pricing Principles set out in the NER require each tariff to be based on the LRMC of providing the service to the retail customers assigned to that tariff class, with the method of calculating such cost and the manner in which that method is applied to be determined having regard to the following:

- The costs and benefits associated with calculating, implementing and applying the method.
- The additional costs associated with meeting incremental demand for the customers assigned to the tariff at times of greatest utilisation of the relevant part of the distribution network.
- The location of customers and the extent to which costs vary between different locations.

In accordance with clause 6.18.5(f) of the NER, we have estimated the LRMC values at each major voltage level of our network for use as the basis of network tariffs.

Changes to the NER in 2021 aimed at integrating DER more efficiently into the electricity network[59] remove previous barriers for export charging and create a framework for DNSPs to charge and reward customers for export into the distribution network. These changes, along with the AER's Export Tariff Guidelines, require tariffs to be set based on LRMC for both import and export services.

8.3.2 NER requirements

As set out in the NER a DNSP's tariff structure should be aligned with the Pricing Principles to reflect sound economic practices whilst protecting consumers. Specific to LRMC, the two primary sections are:

- clause 6.18.5 (a) Network Pricing Objective, and
- clause 6.18.5 (f) Pricing Principles.

8.3.3 LRMC approach in 2020-25 TSS and associated feedback

There are three main approaches for estimating import and export LRMC:

- The perturbation (Turvey) approach.
- The average incremental cost (AIC) approach.
- The long run incremental cost (LRIC) approach.

The Turvey and AIC approaches both involve forecasting costs and demand over a long time period. The LRMC is then determined by dividing the present value of costs attributable to meet a change in anticipated demand by the discounted sum of the anticipated change in future demand. The LRIC approach is based on the cost of building a hypothetical network to supply a total coincident demand of 500 MW. The Optimised Replacement Costs (ORC) forms the basis for LRMC estimation. This was the approach we adopted for the 2020-25 TSS.

[59] For more information on the rule change, see AEMC, Access, pricing and incentive arrangements for distributed energy resources, Rule determination, 12 August 2021. Available at: https://www.aemc.gov.au/rule-changes/access-pricing-and-incentive-arrangements-distributed-energy-resources.

Since LRMC is a forward-looking concept, the AER noted that its estimate should consider a time dimension in both expenditure and demand specific to the network. In response to the AER's decision, we assessed different LRMC estimation methodologies before finalising our approach in the 2025-30 TSS. Our findings are outlined below:

- The AIC approach remains the most widely used industry practice and it is the recommended method for us to adopt to calculate LRMC based on the current and anticipated future state of our network.
- The AIC calculation is an improvement to better match the augmentation costs and the associated increase in demand.
- Expenditure inputs should consist of peak demand growth-related costs such as augmentation costs and growth-related connections costs.
- Common practice is to exclude replacement costs from LRMC estimation where the costs are non-demand driven, noting replacement costs play some role in deriving the cost savings per unit of reduction in demand.
- Minimum demand export charge Pricing Principles should be based on LRMC in a similar way as import charges. Given the anticipated growth in customer export to the distribution networks and associated network augmentation expenditure over the regulatory control period, AIC is the recommended approach to calculate export LRMC at times of minimum demand.

Based on our findings, we have adopted the AIC approach for LRMC estimation for both import and export services in the 2025-2030 TSS.

8.3.4 Average incremental cost approach overview

The AIC method entails estimating the LRMC by considering the expenditure required to meet the forecasted increment demand between each time period (e. g. year), then averaging these costs over the long run period. Conceptually, it involves:

1. forecasting demand over the long run period (e.g.10 years)
2. developing the optimised capex investment plan to meet the forecast demand, and
3. deriving LRMC as the present value of the additional costs of meeting incremental increase in demand divided by the present value of the future increase in demand.

It is calculated as:

$$LRMC = \frac{PV(additional\ costs\ to\ meet\ incremental\ demand)}{PV(incremental\ demand)}$$

8.3.5 Capital expenditure Inputs

Distribution businesses commonly include direct costs driven by the growth in peak demand for AIC calculation. Common categories include:

- growth related augmentation capex, and
- any system augmentation costs that are included in new connections.

The AER suggested the inclusion of replacement costs in LRMC calculation should be included since the decision regarding the timing and size of any replacement may be influenced by the change in demand.

We note the Expenditure Forecast Assessment Guideline by the AER which states:[60]

> *'Replacement expenditure is the **non-demand driven** capex to replace an asset with its modern equivalent where the asset has reached the end of its economic life.'*

This suggests that only the replacement of assets with increased capacity can be considered as demand driven and included in the LRMC calculation. In practice, this type of replacement cost is classified as augmentation cost for many distributors so the entirety of growth-related expenditure in AIC calculation might not consist of any replacement costs.

8.3.6 Import LRMC approach

We have adopted the growth/declining categorisation of zone substations as a refinement to address the assessment criteria of deriving a more cost reflective estimate, as well as investigating the inclusion of replacement expenditure (repex).

We consider expenditure costs relevant to this group are growth-related augmentation and connection costs. No replacement costs have been included because this forecast is non-demand driven. Capacity enhancing capex, where it is demand-driven, is routinely classified as augmentation costs. Growth-related connection costs are input as a percentage of total connection cost.

8.3.7 Export LRMC approach

The export LRMC considers only the augmentation expenditure in a forward-looking manner, similar to that of import LRMC. Customer export capacity is forecast to continue to grow strongly which is consistent with adopting an AIC approach to calculating export LRMC. Export services are largely across the LV network, and with identified investment impact on the LV and HV network assets.

Consistent with our approach to calculating the import LRMC, we have adopted the AIC method for estimating export LRMC. This involves considering the expenditure required to meet the forecast incremental export between each time period (e.g. year), and then averaging these costs over the long run period.

Conceptually, the LRMC calculation involves:

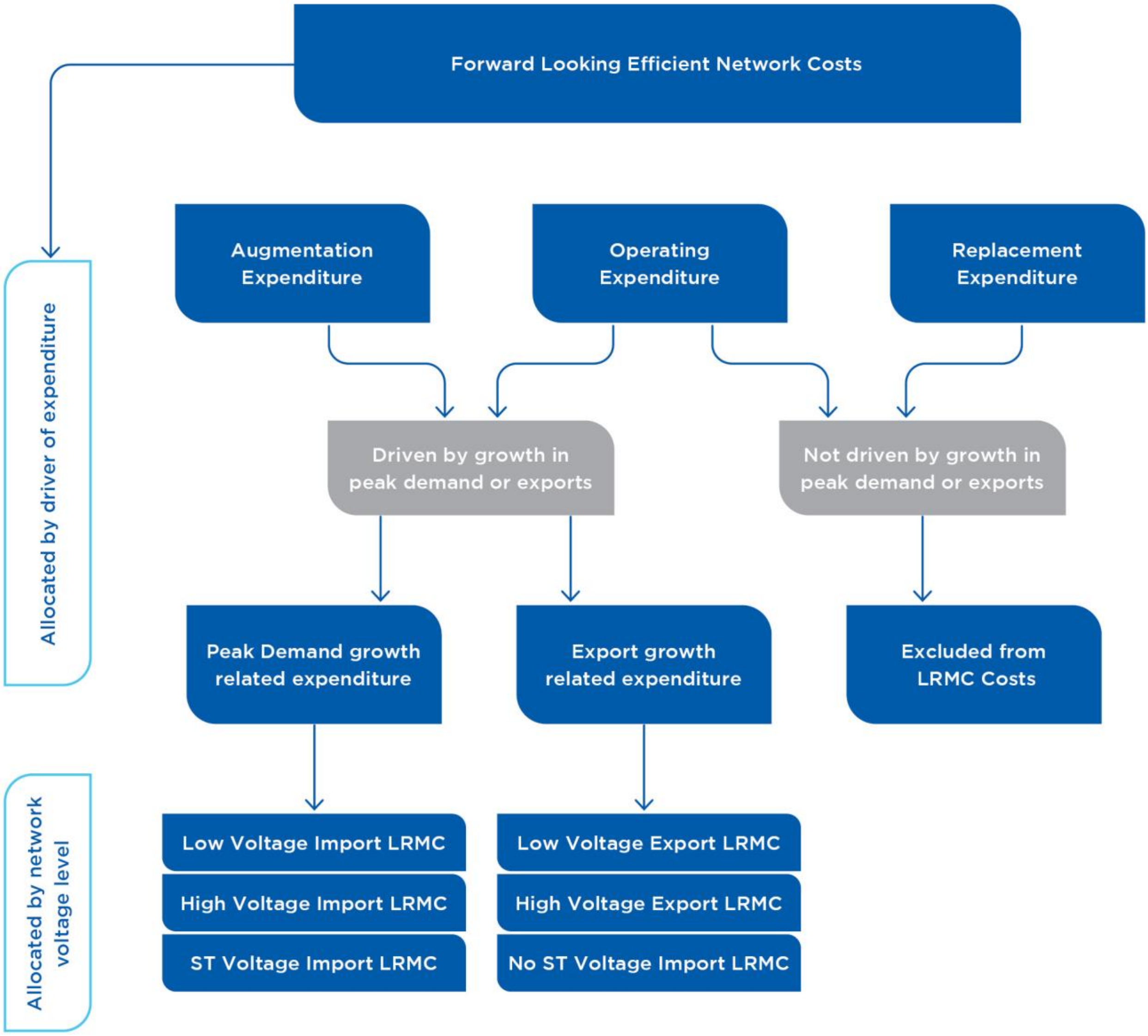
1. forecasting export capacity over the long run period (e. g. 10 years).
2. developing the optimised capital expenditure investment plan to meet the forecasted export capacity, and
3. estimating the present value of the additional costs of meeting incremental increase in customer export divided by the present value of the future increase in export capacity.

Model and results

Figure 6 provides an overview of allocation of network expenditure for import LRMC.

[60] AER, Expenditure Forecast Assessment Guideline, Explanatory Statement, November 2013, page 184.

Figure 6: Import LRMC overview



Control parameters and assumptions

The control parameters are listed in Table 22. These parameters will stay constant over the forecasting horizon.

Table 22: Control parameters and assumptions

Parameter Name	Description
Real Vanilla weighted average cost of capital (WACC)	Real Vanilla WACC
Opex Proportion of Capex[61]	A percentage of total capex to estimate the total opex for each year.
Percentage repex saved per percentage demand reduction	The percentage of total repex that can be saved per percentage demand reduction on average.
Growth Related Repex Percentage	The proportion of total repex that is classified as growth-related.
Growth Related Connections Cost Percentage	The network augmentation proportion of total new connections cost (growth-related).

Granular inputs

The granular inputs required for the model are listed in Table 23. These inputs are sourced from our internal forecasts. The growth/declining group categorisation of zone substations, as discussed above is part of the preparation of our model inputs. There is no granularity by expenditure type for export expenditure.

Table 23: Granular inputs

Parameter Name	Description
Import forecast	Aggregated coincident demand forecast for substations for each granularity combination
Export forecast	Aggregated export capacity forecast for substations for each granularity combination
Import expenditure forecast	Aggregated demand driven expenditure forecasts for substations or programs for each granularity combination
Export expenditure forecast	Aggregated export driven expenditure forecasts programs for each granularity combination
Asset Specification	Asset specification and loss factors such as Distribution Loss Factors (DLF) and Power Factors (PF) for assets in each granularity combination

Demand and export capacity summary

Existing demand/capacity refers to the total demand/capacity aggregated to the stated granularity. Incremental demand/capacity is the growth each year. The net present value (NPV) of incremental demand (or existing demand for import declining category) will be used for LRMC calculation.

Expenditure

The formula of total capex varies between each category. While the import declining group only accounts for reduced replacement cost as capex and export capacity group takes total capex as input, the import growing group calculates the total capex as:

$$Total\ capex = augex + \%growth\ repex \times repex + \%new\ connections \times connections\ cost$$

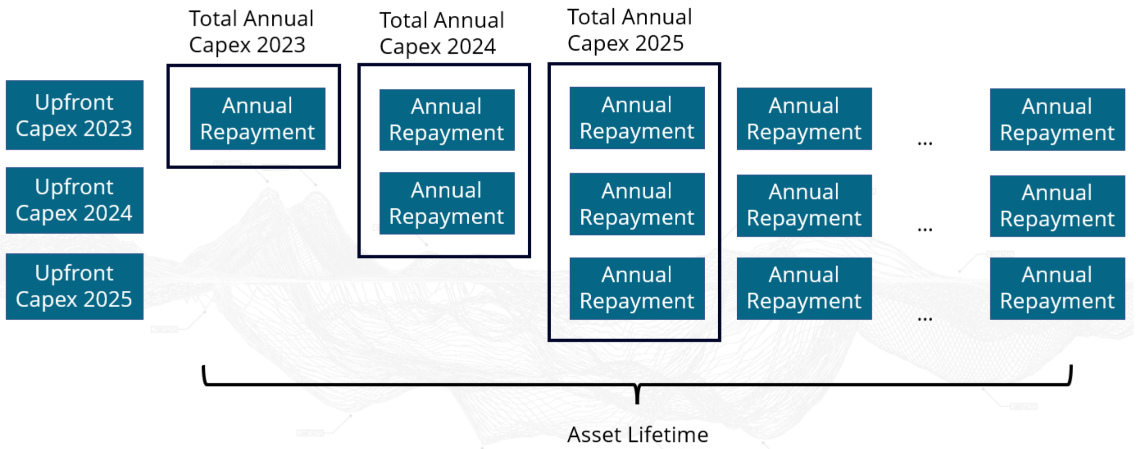
[61] As noted above, the functionality for classifying growth-related repex as a percentage of total repex is to preserve model versatility, rather than the proposed recommendation on the treatment, of repex.

The tables in the model lay out sequentially each calculation step applied to the expenditure data throughout the LRMC calculation. The LRMC model (Ergon - 9.05 - Endgame Economics LRMC model - January 2024 - public):

1. Calculate total capex and (opex as a percentage of capex).
2. Annualise capex by splitting the total upfront capex into annual payments over the asset's lifetime, discounted by WACC.
3. Calculate cumulative annualised capex – the total annual capex payment from all previous years plus new annualised capex incurred at present year (as described in Figure 7: Annualising capex payments)
4. Total annual cost is the sum of cumulative annualised capex and opex.
5. Calculate the repex saving by multiplying the total annual cost by the percentage repex saved per percentage demand reduction.

The resultant total annual cost each year will be used to calculate the NPV of expenditure for LRMC estimation.

Figure 7: Annualising capex payments



LRMC segmentation

To provide clarity and transparency in cost reflectivity for customers, segmentation of LRMC is considered to allocate LRMC to each part of the network. In other words, when a consumer decides to produce an additional unit of output at any voltage level, the following cost allocations are calculated:

- The costs to each of the upstream assets.
- The aggregated total cost to all upstream assets.

The cost allocation procedure splits the NPV of total costs for any asset to each of the downstream consumers by coincident demand proportions. Figure 8 and Figure 9 describes this approach:

Figure 8: Example cost segmentation to upstream assets for consumers

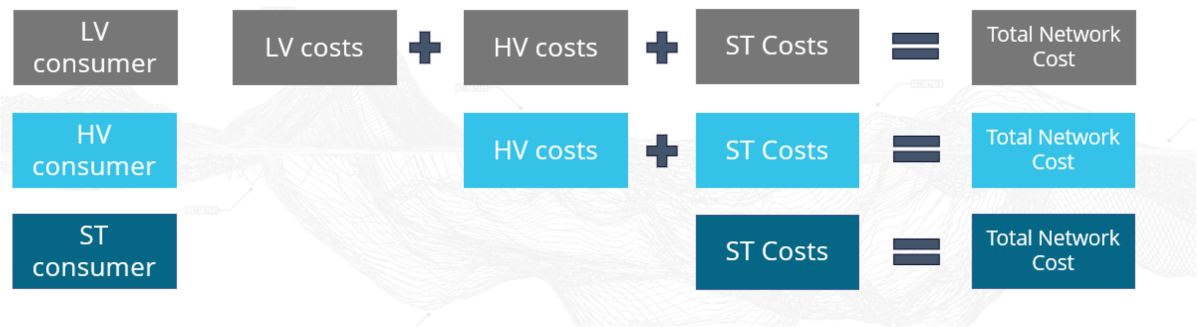
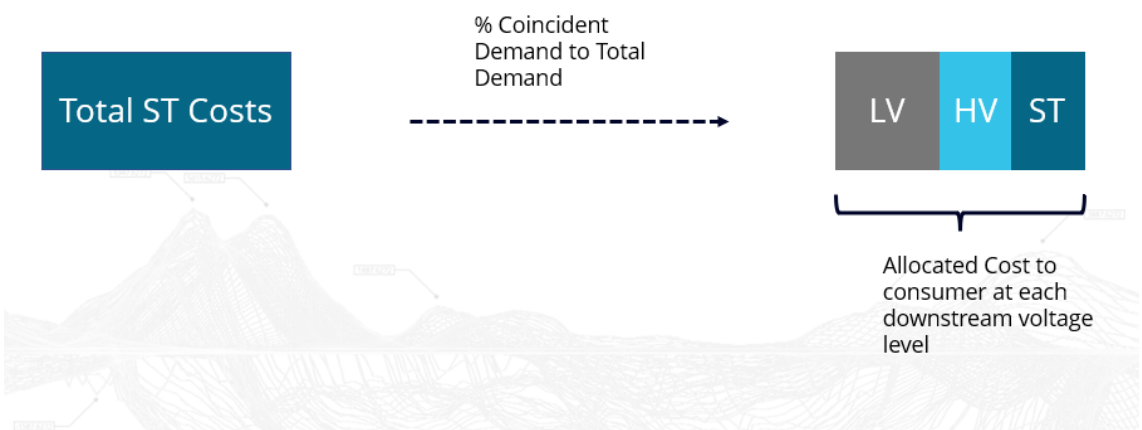


Figure 9: Example allocation of asset costs to downstream consumers



The LRMC assigned to consumers at each voltage level is estimated by dividing the allocated total network costs by the NPV coincident demand. Further, dividing any voltage level allocated costs by the NPV coincident demand will give an isolated LRMC estimate specific to the costs incurred to the assets at that voltage level. Note that the segmentation approach is analogous for the import declining group where the NPV reduced costs is used in place of NPV total costs.

8.3.8 LRMC estimates

LRMC estimates for each voltage level are provided in our TSS. We have retained the LRMC estimates submitted in our Initial TSS. This is consistent with no material change to the inputs. We note our decision on two-way tariffs in the Revised TSS means that the export LRMC estimates will not be applied in the 2025-30 regulatory control period. We have retained the methodology we described in the Initial TSS for completeness.

8.4 Recovering efficient costs and minimising distortionary signals

Pricing Principles require that our tariffs and charges should reflect our efficient costs of providing standard control services.

Our approach to allocating costs and setting distribution tariffs involves the following:

- Setting prices for LRMC based charges and reflecting the estimated LRMC in the peak demand and peak volume tariff charging components.
- Allocating the residual costs to each tariff class and then to the non-LRMC based charges.
- Ensuring revenue for each tariff class lies between the stand alone and avoidable costs.

We attribute relative costs of the network to voltage levels based on the relative contribution of the tariff class to the voltage level. For example, the LV tariff class receives a larger distribution cost allocation given a LV connection uses more network assets. Residual costs are firstly allocated to each tariff class and then to the individual charging components within each tariff.

Costs not recovered from LRMC based charges are recovered from non-peak volume and demand charges and fixed charges. Residual costs are allocated to the individual tariffs on a basis that minimises changes relative to the previous year and takes into account customer impacts.

Our TSS provides our detailed tariff setting methodology, including our approach for allocating costs to the individual tariffs and setting of charges within each individual tariff.

8.5 Impact on retail customers

Our engagement approach tested customer preferences to the pace of change to network tariff reforms necessary for efficient customer outcomes, given the rapid energy sector and environment changes. We have also tested outcomes of different tariff structures and prices having regard to network bill impact for all customers and, in some cases customer segments, to ensure we balance equity and fairness in the short term with efficient tariff design.

During our engagement phase, customers asked us to do more to inform and educate customers on tariff structures and impacts for customers. We have already addressed some concerns by refining our website material and information sheets. We aim to address other concerns with additional information and education over time.

8.6 Compliance checklist

Table 24 demonstrates our compliance against the NER.

Table 24: Compliance Checklist

Rule Reference	Requirement	Document Reference
6.8.2	**Submission of regulatory proposal, TSS and exemption application**	
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 TSS related to the distribution services provided by means of, or in connection with, the Distribution Network Service Providers distribution system.	TSS Section 1.1
6.8.2(a1)	A Distribution Network Service Provider must submit to the AER any exemption application for an asset exemption under clause 6.4B.1(a)(1) or 6.4B.1(a)(2) for the regulatory control period at the same time as submitting the relevant regulatory proposal under paragraph (a).	Noted
6.8.2(b)	A regulatory proposal, a proposed TSS 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
6.8.2(c)(7)	A regulatory proposal must include a description (with supporting materials) of how the proposed TSS complies with the Pricing Principles for direct control services including: (i) a description of where there has been any departure from the Pricing Principles set out in paragraphs 6.18.5(e) to (g); and (ii) an explanation of how that departure complies with clause 6.18.5(c).	Explanatory Statement Chapter 8 TSS Chapter 5
6.8.2(c1)(2)	The regulatory proposal must be accompanied by an overview paper in reasonably plain language which includes a description of: (i) how the Distribution Network Service Provider has engaged with relevant stakeholders including distribution service end users or groups representing them and (in relation to the TSS) retailers and Market Small Generation Aggregators in developing the regulatory proposal and the proposed TSS including the export tariff transition strategy; (ii) the relevant concerns identified as a result of that engagement; and (iii) how the Distribution Network Service Provider has sought to address those concerns;	Explanatory Statement Section 5 and 6 Regulatory Proposal

Rule Reference	Requirement	Document Reference
6.8.2(c1)(5)	The regulatory proposal must be accompanied by an overview paper in reasonably plain language which includes a description of the key risks and benefits for distribution service end users of the regulatory proposal and the proposed TSS including the export tariff transition strategy;	Explanatory Statement Section 6.2 Explanatory Statement Chapter 8 Regulatory Proposal
6.8.2(d1)	The proposed TSS must be accompanied by an indicative pricing schedule.	Attached
6.8.2(d2)	The proposed TSS must comply with the Pricing Principles for direct control services.	TSS Chapter 5 Explanatory Statement Section 8
6.8.2(e)	If more than one distribution system is owned, controlled or operated by a Distribution Network Service Provider, then, unless the AER otherwise determines, a separate regulatory proposal and a separate TSS are to be submitted for each distribution system.	TSS Section 1.1
6.8.2(f)	If, at the commencement of this Chapter, different parts of the same distribution system were separately regulated, then, unless the AER otherwise determines, a separate regulatory proposal and a separate TSS are to be submitted for each part as if it were a separate distribution system.	Noted
6.18.1A	**TSS – must include:**	
6.18.1A(a)(1)	the tariff classes into which retail customers for direct control services will be divided during the relevant regulatory control period	TSS Section 2.1
6.18.1A(a)(2)	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)	TSS Chapter 4, appendix B
6.18.1A(a)(2A)	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)	Explanatory Statement Section 6.3, 5.4 TSS Chapter 6
6.18.1A(a)(3)	the structures for each proposed tariff	TSS Chapter 3, appendix A
6.18.1A(a)(4)	the charging parameters for each proposed tariff	TSS Chapter 3 Indicative Price List
6.18.1A(a)(5)	a description of the approach that the Distribution Network Service Provider will take in setting each tariff in each pricing proposal of the Distribution Network Service Provider during the relevant regulatory control period in accordance with clause 6.18.5 Note Under clause 11.141.13(a), a TSS 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.	TSS Chapter 5 and 6 Explanatory Statement Chapter 8

Rule Reference	Requirement	Document Reference
6.18.1A(b)	A TSS must comply with the Pricing Principles for direct control services.	TSS Chapter 5 Explanatory Statement Chapter 8
6.18.1A(e)	A TSS 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 TSS.	Attached
6.18.3	**Tariff classes**	
6.18.3(b)	Each retail customer for direct control services must be a member of 1 or more tariff classes	TSS Section 2.1
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 retail 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
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.	TSS Section 2.1
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
6.18.4(a)(1)	retail customers should be assigned to tariff classes on the basis of one or more of the following factors: (i)the nature and extent of their usage or intended usage of distribution services; (ii)the nature of their *connection* to the network; (iii)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;	TSS Section 2.1
6.18.4(a)(2)	retail customers with a similar *connection* and distribution service usage profile should be treated on an equal basis, subject to subparagraph (3A)	TSS Section 2.1
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	Explanatory Statement Section 4.2

Rule Reference	Requirement	Document Reference
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.	TSS Section 2.2
6.18.4(b)	If the charging parameters for a particular tariff result in a basis of charge that varies according to the distribution service usage 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.	TSS Section 2.2
6.18.5	**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.	TSS Chapter 5 Explanatory Statement Chapter 8
6.18.5(b)	Subject to paragraph (c), a Distribution Network Service Provider's tariffs must comply with the Pricing Principles set out in paragraphs (e) to (j).	TSS Chapter 5 Explanatory Statement Chapter 8
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: (1) to the extent permitted under paragraph (h); and (2) to the extent necessary to give effect to the Pricing Principles set out in paragraphs (i) to (j).	TSS Chapter 5 Explanatory Statement Chapter 8
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.	TSS Chapter 5 Explanatory Statement Chapter 8
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.	TSS Chapter 5 Explanatory Statement Chapter 8

Rule Reference	Requirement	Document Reference
6.18.5(f)	Each tariff must be based on the LRMC 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 service; 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.	TSS Chapter 5 Explanatory Statement Chapter 8
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 (3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage of the relevant service that would result from tariffs that comply with the Pricing Principle set out in paragraph (f).	Pricing Proposal Explanatory Statement Chapter 8
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: (1) 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); (2) the extent to which retail customers can choose the tariff to which they are assigned; and (3) the extent to which retail customers are able to mitigate the impact of changes in tariffs through their decisions about usage of services.	TSS Chapter 5 Explanatory Statement Chapter 8

Rule Reference	Requirement	Document Reference
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.	TSS Chapter 5 Explanatory Statement Chapter 8
6.18.5(j)	A tariff must comply with the NER and all applicable regulatory instruments.	Noted
11.141.13	**Basic export level to be specified in TSS's**	
11.141.13(a)(1), (2)	For the purposes of new clause 6.18.1A(a), a TSS of a Distribution Network Service Provider that will apply during the tariff transition period for the Distribution Network Service Provider must include, in addition to the elements in new clause 6.18.1A(a): (1) for each proposed export tariff, the basic export level or the manner in which the basic export level will be determined; and (2) the eligibility conditions applicable to each proposed export tariff.	TSS Chapter 6 Explanatory Statement Chapter 6

Page intentionally left blank.

APPENDIX A – DYNAMIC CONNECTIONS

The rapid growth of solar generation from house rooftops and solar farms during daylight hours is resulting in the need to manage new and rising challenges relating to minimum demand on the network. Minimum demand can best be described as the lowest energy operational demand across an electricity network at a point in time.

Left unmanaged, lower minimum demands (particularly when experienced with high demands at other times) can create issues around local power quality that can be harmful to customer appliances as well as the network.

Day-time minimum demand windows which can create reverse power flows in localised parts of our network. Reverse flows can impact power system security, threatening the ability to withstand major events. Additional infrastructure will be required in the future to manage the additional energy being exported to the network, along with options that ‘soak-up’ the generation from solar and put it to good use for customers.

The challenge for networks like Ergon Energy Network is to balance the need for additional investment with other options in a way that maximises outcomes for all customers in terms of safety, reliability and affordability.

A dynamic connection is a relatively new connection option for flexible Consumer Energy Resources such as solar PV, battery and EV charging installations. It allows additional excess energy to be exported at most times, while ensuring a safe and reliable electricity network is maintained at times of congestion.

Dynamic Connections avoid imposing static limits in some geographic areas allowing customers to export excess energy to the network, even where the local area is already considered saturated with solar connections. Importantly, dynamic connections allow more solar capacity to be hosted on the network, often without the need for investment in additional infrastructure. Dynamic connection approaches are included in our QECM and relate to how the network may communicate with Ergon Energy Network customers in different periods, for example, times of congestion.

For storage customers, we are offering lower charges compared to our default tariff in return for controlling generation and load at times of constraints through dynamic connections.

Dynamic Connections and Dynamic Operating Envelopes

DOEs are dynamic import and export limits communicated to a site to manage power flows at the connection point in accordance with local network capacity and network performance requirements. Application of DOEs allow customers to improve value from their investments without affecting lifestyle while optimising the network utilisation by allowing higher export and import limits when the local network has more hosting capacity.

With a dynamic connection, the DOE signal is sent from our network to the customer’s site. Signals are sent in 5-minute intervals, using Wi-Fi or a hard-wired internet connection. The signals will tell customers battery system how much imported load or exported generation our network can accept at that point in time.

This means, instead of fixing limits on how much energy is imported or exported at a connection to meet all possible network constraints, higher limits are made available with the ability to reduce in response to network conditions. This enables more load or generation to be imported or exported, more often.

Difference between “static” and “dynamic operating” envelopes

Historically, operating envelopes have been provided as fixed limits based on the capacity of the network. As they are static, they must allow for worst-case conditions into the future. Figure 10 describes how a static export limit will apply to a connection.

Figure 10: Static Export Limit

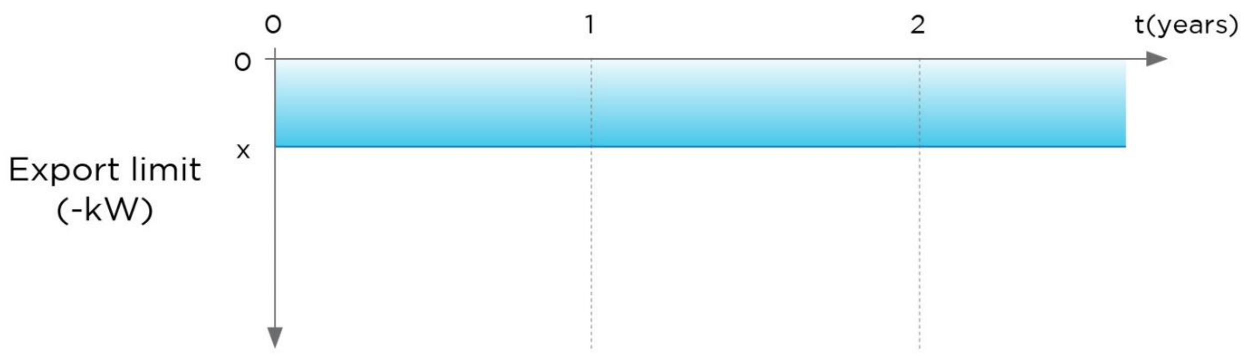
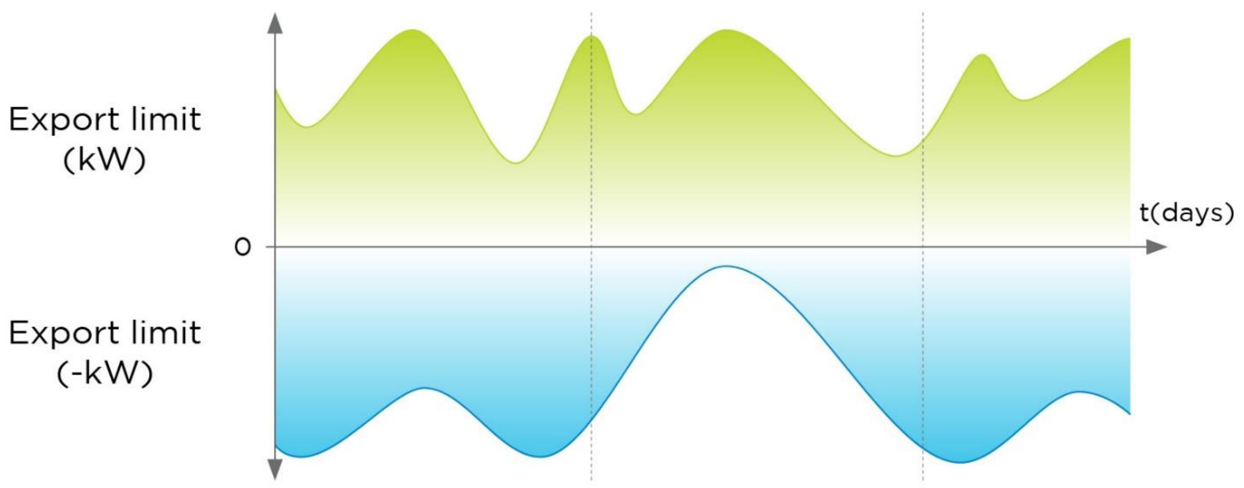


Figure 11 shows how a DOE would apply. The DOEs allow import and export limits to vary over time and location. Dynamic export limits can enable higher levels of energy exports from consumer energy resources such as solar PV, battery energy storage systems or even vehicle-to-grid enabled EVs by allowing higher export limits when there is more hosting capacity on the local network.

Figure 11: Dynamic Operating Envelope



DOEs are currently being calculated using a ‘Basic Schedule’ methodology making use of an assumed worst-case seasonal load curve for each transformer. This means that customers will receive the same DOE every day for that season. Under this methodology, customers on un-constrained transformers will never be limited, unless overridden by an operator (noting that load curves will be updated periodically, and transformers could become constrained in the future).

We intend to support more advanced calculation methodologies in the future, which should result in customers being constrained for less of the year (but likely still constrained at minimum demand times). Advanced calculation methodologies may not be available in all areas, as it will rely on Power Quality Transformer Monitoring or State Estimation being available for that transformer. Our newly released Capacity Map[62] will allow customers and installers to determine whether their particular transformer has an existing consumer energy resource constraint or not.

DOE allocation methodology options

Given that DOEs are still in the early stages of development, capacity allocation methodologies are in their infancy and will evolve as penetration of consumer energy resource increases and network monitoring capabilities are advanced.

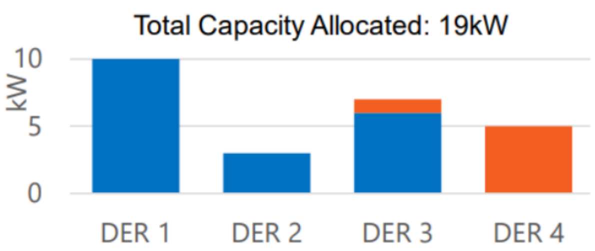
As an interim measure Ergon Energy Network has considered available capacity allocation methodologies to calculate DOEs for dynamic connections.

Three methodologies were considered:

- The optimised (maximise) allocation
- Equal shared individual allocation
- Proportional asset allocation

Figure 12 shows the impact of applying the **optimised, maximised allocation methodology** where the headroom is exhausted using an optimised solution.

Figure 12: Optimised allocation approach



We assessed this approach as follows:

Pros:

- Aligned with the AER principle for minimising Customer Export Curtailment Value.
- Maximum renewable energy exported.

Cons:

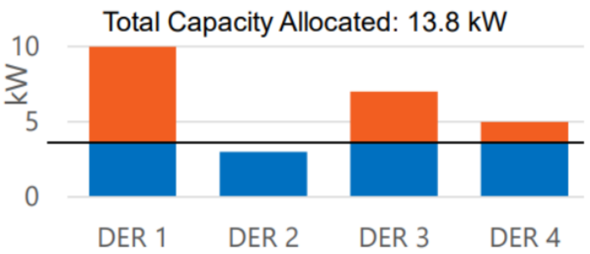
- Requires accurate network model.
- Lower allocations for customers further away from the distribution transformer.
- Potentially unfair as customer at end of line will lose more energy export than those close to transformer (particularly on sunny days).

Figure 13 shows the impact of applying the **Equal share individual allocation** where the headroom is equally assigned to customers up to the maximum allowed limit for each connection.

---

[62] See: https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/network-load-capacity-map.

Figure 13: Equal share individual allocation approach



We assessed this approach as follows:

Pros:

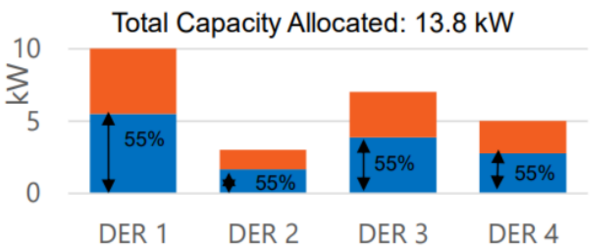
- Does not favour big systems/customers.
- Positive customer reaction expected.
- Fewer systems curtailed on average (due to higher number of small systems).
- Does not require an accurate network model.

Cons:

- Does not maximise the total amount of renewables exported which could be beneficial for the overall system/community.

Figure 14 shows the impact of applying the **Proportional asset** where the headroom allocated in proportion to the generation capacity behind each connection point.

Figure 14: Proportional asset



We assessed this approach as follows:

Pros:

- Simplest to allocate and maintain
- Doesn't require an accurate network model.

Cons:

- More customers get limited export.
- Connection of additional large systems may substantially alter allocations of existing dynamic connections.
- Doesn't maximise the total amount of renewables exported.

Current DOE allocation method

Ergon Energy Network's preferred method at this stage of development is equal share individual allocation. This approach intends to ensure some measure of "fairness" for customers whilst also providing a simple mechanism for generating DOEs particularly when limited network model data or telemetry are available. It is expected that this methodology will act as a solid starting point for future and more advanced DOE allocation methodologies.

The Optimise allocation methodology requires accurate models and more telemetry data to determine the optimal allocation to maximise the overall export, as the distance of customers from the distribution transformer influences their allocation. Because of this, the Optimise allocation methodology is deemed to be inappropriate for application at this time. Implementation of DOEs across Australia and relevant policy reforms will influence future allocation methodologies.

Note, absolute transparency of DOE constraints for customers ahead of time is difficult due to the dynamic nature of energy flows across the network. However, guidance can be provided through using historical data.

Dynamic connection application process

Outlined below is the process[63] for negotiating a dynamic connection for any generation (including solar, batteries and rotating machines). Systems under 30kVA skip the enquiry stage and do not need to do a Design Compliance Report (DCR). At present, all dynamic applications are negotiated (require manual handling), we anticipate that by next year there will be a basic offer for dynamic in which case they will be auto approved.

Phase 1 Enquiry phase

Steps include:

1. The customer would submit an enquiry through our Online Portal (Ergon: Our portals | Ergon Energy Network), outlining installer details, type and size of system installed.
2. Ergon Energy Network reviews customers enquiry for completeness within 2 business days.
3. If the customers enquiry application is complete, Ergon Energy Network or Energy Queensland staff develop a Site Specific Enquiry Response which contains indicative information on permitted capacity and export/import limits, with advice on the likely difference in options between a fixed and dynamic connection (a fixed system for example may be required to have a nil-export or very small fixed export if the network is constrained). Ergon Energy Network or Energy Queensland staff will complete this within 45 business days of the enquiry being received.

Phase 2 Application phase

Steps include:

1. The customer submits DCR which demonstrates that the installer has appropriately designed the system considering all of the standard's requirements.
2. DCR and application assessed within two business days.
3. If the application is compliant, the customer will proceed to a DCR compliant, Technical Assessment. A technical assessment confirms the capacity and export permitted (a dynamic system will have a maximum permitted export and import, as well as fixed and minimum limits).

[63] Process applies for small customers, that is, LV under 1,500kVA generation capacity. Similar processes apply for HV connected, with increasing complexity for larger generation.

4. If the application is not compliant the customer will go back to the DCR application step, noted at step 1, phase 2.
5. If the customers application is compliant, the customer will proceed to a technical study and an offer is emailed to the customer within 65 business days. In the technical study the customer will receive specifics about the network connection that they will be connected to, (i.e. the feeder, the line, the amount of energy that they can import or export and, if there are any additional costs to augment the network for the size of the load the customer is proposing to connect to the network).
6. The customer has 20 business days to sign the offer.
7. Following completion of the offer being executed by both the customer and Ergon Energy Network or Energy Queensland staff, the offer is uploaded to Portal.

Phase 3 Installation and Testing phase.

Steps include:

1. A compliance report submitted for Registered Professional Engineer of Queensland review within 20 business days.
2. If the compliance report is not compliant the customer will go back to the compliance report submission step, noted at step 1, phase 3.
3. If compliance report compliant, the compliance report is uploaded to the Online Portal.
4. Electrical Works Report submitted within 10 business days to the Portal which marks the end of the process.

Dynamic connection agreement will outline DOE operational limits, compliance requirements, and penalties for non-compliance. Process in place ensures customers clearly understand the terms and conditions of agreement before signing.

APPENDIX B – QECM AND TSS

What is the QECM?

The purpose of the QECM is to outline the requirements for connecting to and interfacing with our distribution system as the service and installation rules. It has been developed to ensure the safe and stable operation of electrical installations connected to the distribution system without causing material degradation in the quality of supply to distribution system users. The document is primarily used by electrical contractors, engineers, consultants, builders, developers, architects, metering providers, and others directly concerned with electrical installations that are connected, or are to be connected, to the distribution system.

What is the intent of the QECM in relation to managing customer loads?

The QECM contains technical connection requirements associated with active device management which have been in place in Queensland for decades. The QECM requires (section 8.14.2.2) certain types of loads (for example, single phase loads greater than 20 amps per phase) to be installed and configured to achieve 'active device management', to ensure safe and secure management of the distribution system. Active device management allows us to manage a customer's appliance (infrequently and temporarily interrupting supply or reducing the output of the customer's appliance) to assist in managing the load on the network.

The QECM was updated in February 2024, which expanded the active device management options available, including new options to allow for these devices to be connected without the need for separate metering from other loads at the metering point. These changes were in response to increased installation of consumer energy resources like EVSE and the desire for customers to be able to utilise their own solar generation for times when the appliance is not subject to active device management.

In relation to managing customers loads, the main active device management options are:

- A network owned device using AFLC in a ON/OFF control approach (this is the existing / legacy load control management system.
- A dynamic connection – allowing for ramp up / ramp down management of customer equipment without the need for separate measurement for pricing purposes (a recently implemented capability that involves publishing of variable DOE settings by the network for the customer device which is enabled directly or indirectly via the CSIP-AUS protocol).

How does the QECM relate to a customer's network tariff options / choices?

The QECM sets out multiple connection options for customer loads. Some connection options (8.14.2.2) require active device management. This includes where:

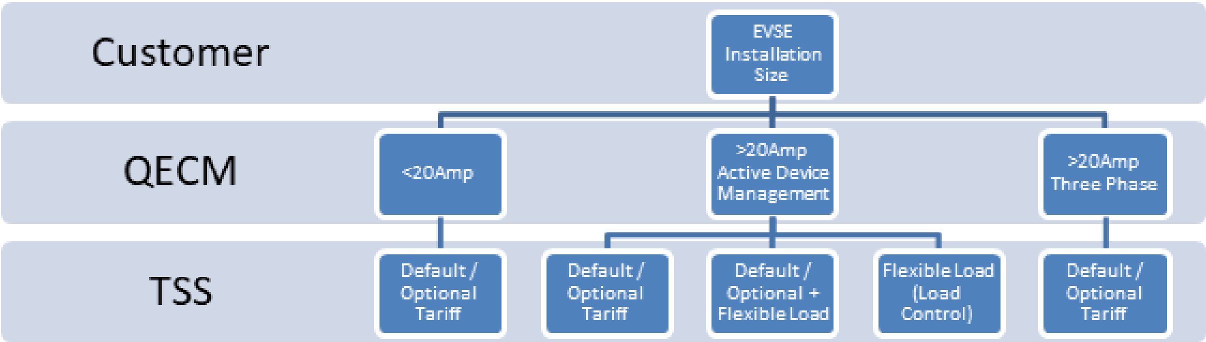
- load thresholds in the QECM are exceeded, as outlined above, or
- where a smaller load (for example, a hot water system) is voluntarily connected to a secondary load control tariff by a customer in order to be eligible for concessional tariffs.

The QECM V4.0 does not mandate customer assignment to tariffs and does not specify which network tariff a customer must choose. For example, the flexible load tariff is enabled by several device management options in the QECM. In our conversations with customers, they have informed us that optionality is important. By providing multiple active device management options, and eligibility for different tariffs depending on the choice of active device management, the QECM supports this goal.

Incentives inherent in the secondary load control tariffs and the flexible load tariffs are designed to reflect the ongoing network demand benefits associated with the customer choice to opt into a connection option that includes load management and are not designed to encourage compliance with the QECM or to offset costs associated with compliance.

In relation to EV charging for sites 100 amps or less (typically residential premises and small business), Figure 15 outlines how the QECM and tariff options interrelate.

Figure 15: QECM and tariff options



APPENDIX C – RESPONDING TO THE AER'S SPECIFIC CONCERNS AROUND APPLIANCE CONTROL

Explanation of how active device management works for a customer without a flexible load or load control tariff

Active device management is an umbrella term in the QECM to describe the various methodologies for Ergon Energy Network to manage the loads of particular appliances or connections, to help manage network demand and reduce the need for network augmentation.

Traditionally, active device management has involved controlled load or controlled supply where loads are wired separately from other appliances, are controlled by means of frequency injection receiver or time clock and are separately metered from the remaining load at the metering point.

In February 2024, after significant stakeholder consultation, the load management options in QECM were expanded to add the options of appliance load control without the need for separate metering. Two additional options now facilitate the customer being able to utilise any on-site generation to offset their EVSE charging which helps to reduce a customer's bill, while maintaining compliance with the QECM.

These options apply to customers in premises connected to 100 amp supply or less (residential premises and some small businesses). These options are:

1. EVSE connected on a primary tariff – with the EVSE controlled via a network device (i.e. audio frequency load control AFLC load control relay), and
2. Dynamic EVSE – with the EVSE controlled via communication between the DNSP's SEP2 server and the customer device, a compliant gateway device, or a third party cloud proxy (platform).

Option 1 uses the same network device as is used for traditional controlled load connections, but without separate controlled load measurement at the meter. This means all load from the device is measured with other loads and included within the primary tariff. Customers can request this option by arranging their electrical contractor to submit an Electrical Work Request under option 2 dynamic control, our SEP2 server communicates directly or via a third party pathway, with the customer equipment (EVSE).

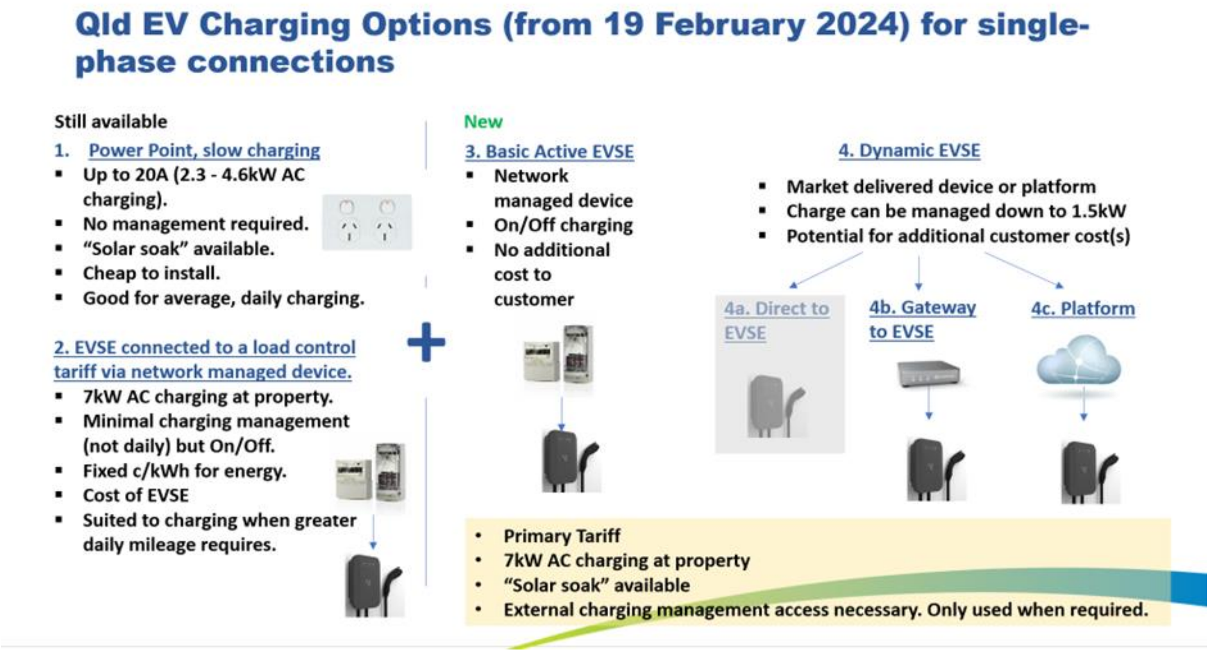
Confirm if there is a situation under which an EV owner must be on a flexible load and/or controlled load tariffs and under what circumstance they can move off those tariffs if a customer had opted into them.

In premises connected 100 amps or less (residential premises and some small businesses), the QECM requires that loads greater than 20 amps per phase (around 5kW), must be connected under one of the three approved methods for active device management. These are:

1. EVSE connected to a traditional controlled load connection enabling a secondary network load control tariff, via a network device (i.e. AFLC load control relay)
2. EVSE connected on a primary tariff, with the EVSE controlled via a network device (i.e. AFLC load control relay), and
3. Dynamic EVSE, with the EVSE controlled via communication between the DNSP's SEP2 server and the customer device; a compliant gateway device; or a 3rd party cloud proxy (platform).

Figure 16 provides further explanation of the charging options and their features (further clarification of the interaction of the QECM and tariffs is provided in Appendix K):

Figure 16: Queensland EV Options (from 19 February 2024)



Customers make choices based on their own circumstances and/or charging preferences. Of the three options, only option 2 above requires a secondary load control tariff because it is separately metered. Where a customer chose the secondary network load control tariff and later opted to move off it, the customer is entitled to move off this tariff at any time. However, to remain compliant with the QECM, customers would need to choose one of the other two options, or upgrade to 3 phase supply.

Options 3 and 4 are tariff agnostic and can be applied to almost any primary tariff. The residential flexible load tariff would apply a tariff incentive for customer opting for either of those two options. Similar to the above, a customer would be entitled to move off this tariff at any time, and as long as they retained the applicable load management options, would remain QECM compliant.

Explain the costs for customers associated with:

- **opting into active device management vs three phase**
- **any device needed by the customer to enable either primary or secondary load control, and**
- **moving between options (e.g. between primary and secondary tariff load control or between active device management and three-phase).**

Opting into active device management vs three phase

Customers deciding to charge their EV from home will need to install EVSE equipment which can cost between $1,000 to $2,500 plus installation costs. Costs to enable EVSE to be connected to the network are in addition to these costs. Alternatively, customers can charge through a power point up to 20 amps and incur no additional costs.

Costs associated with opting into active device management will vary by premise and by the option selected. For connection options involving a network device, these will require:

- supply and installation of the network device by Ergon Energy Network (no cost to the customer), and
- minor electrical works on site to prepare the meterbox for the network device installation (usually minimal costs as these can be undertaken with the EVSE is being installed).

For the dynamic EVSE options, currently this requires a gateway hardware device to be supplied and installed, alongside the EVSE (as there are limited EVSE's in Australia that have SEP2 capability. Indicative costs are around $600 for the hardware plus any installation costs.

Where a customer opts to upgrade from single phase to three phase connection, costs vary significantly depending on the individual circumstances of the connection and the customers' electrical installation. Upgrading to 3 phase power is site specific with costs ranging from $5,000 - $10,000. There are no charges for a customer to change network tariffs after they have upgraded from a single-phase to a three-phase connection.

Any device needed by the customer to enable either primary or secondary load control

Customers who request either the secondary load control or the load control on primary tariff will have a network device installed, being an audio frequency load control relay. There is no charge from Ergon Energy Network for the supply and installation of this device. For the vast majority of customers, this device has the capacity to interrupt and return supply to the controlled loads. For Business customers opting for secondary load control and connecting large loads (for example large agricultural pumps that can have motor sizes of around 45kW), will need to install, at their own expense a device known as a "contactor". The contactor is required to enable the safe switching of these large loads that exceed the switching capacity of the standard network relay. Costs can vary based on the application but would generally start from $1,500 - $2,000.

As noted above, customers who choose the flexible load tariff through dynamic management arrangements will need to install an EVSE that is able to be registered with our SEP2 server. Currently this typically requires intermediary gateway hardware in most cases (due to the lack of EVSE with integrated SEP2 capability), this costs approximately $600 plus installation.

Moving between options (e.g. between primary and secondary tariff load control or between active device management and three-phase).

Where a customer moving between active device management options requires the installation of an Ergon Energy Network load control device, that device will be supplied and installed by Ergon Energy Network at no cost to the customer. Where a customer moving between active device management options require the removal of an Ergon Energy Network control device, alternative control service (ACS) charges will be applied.

Where a customer who had installed one of the active device management options and then chooses to upgrade to three-phase power, assuming they no longer want to access the primary or secondary load control tariffs, they would nominally remove the load control equipment. If that was a network device, there is an ACS charge. If it was via a dynamic management, that would be whatever equipment they had installed.

APPENDIX D - FLEXIBLE LOAD TARIFF

Aim / intent of tariff:

To grow the load under dynamic forms of control in customer premises, particularly the large emerging load of EVSE (7kW and above), whilst providing customers with a suitable ‘reward’ in the form a reduced daily fixed charge.

Proposed Conditions:

The basis for developing conditions for the proposed flexible load network tariff is consistent with conditions for the existing load control network tariffs which exist in Appendix B of the Network Tariff Guide. As discussed in Section 6.5 operating conditions outlined in the Network Tariff Guide may change to reflect operational changes[64] or modifications to the QECM that need to be reflected in the conditions.

The Flexible Load Rebate Tariff conditions comprise of two parts, based on the control being via:

- Flexible load management via Network device.
- Flexible load management via dynamic control.

Table 25 explains the flexible load management via basic active management via network device.

Table 25: Flexible load management via basic active management via network device

CRITERIA	REQUIREMENT
Availability of supply	Electricity supply will be available for a minimum of 18 hours per day during time periods set at the absolute discretion of the DNSP. In emergency conditions as an alternative to removing all supply, we reserve the right to control the load for periods in excess of the times stated in the tariff conditions.
Eligibility Criteria for Load Control Tariff access	Smart metered or basic metered customers only. Customer must be in an area that the relevant DNSP is able to actively reduce and/or remove and reinstate supply through the DNSPs standard load management signalling technologies (outlined below). Customer must maintain 1 or more eligible equipment connected via the method outlined in ‘Technical and Wiring Requirements’. The DNSP will remove access to this tariff where a premise is found to no longer comply with this criteria.

*The operational considerations below will need to include the ability of retailers to be aware if a customer premise meets these criteria – as both the EVSE on Primary and especially dynamic – does not normally involve an interaction with retailers that results in these being recorded against a NMI.

Retailers will need to this information to be able to advise which of their customers are eligible to apply to move to this network tariff.

[64] For example, changes to the hours of supply where there is network justification, and able to be managed without negative customer impacts.

CRITERIA	REQUIREMENT
Technical and Wiring Requirements	The premises must have been wired in accordance with the requirements of the QECM at the time of requesting access to the tariff and must comply with jurisdictional metering requirements. Customers must have 1 or more* eligible equipment (see below), connected under **basic active management via network device**, supplied by us (refer to QECM 8.10.5 & 10.6); Hard wired equipment only Any additions and alterations to the electrical installation to enable load control equipment to be installed, as per the QECM requirements, is the responsibility of the customer e.g. contactors and meter wiring.
Eligible Equipment to be connected to tariff	Eligible equipment: EVSE (EV Chargers) rated at 7 kW or above.

Table 26 sets out our flexible load management via dynamic control

Table 26: Flexible load management via dynamic control

CRITERIA	REQUIREMENT
Availability of supply	• Dynamic and fixed import limits will apply, dependent on the network demand. Refer to the published Terms and Conditions, available via www.ergon.com.au/evse
Eligibility Criteria for Load Control Tariff access	• Smart metered or basic metered customers only. • Customer must be in an area that is able to maintain a reliable connection (directly or indirectly) to the DSNP's SER2 server (in practice, reliable broadband or 4G service is required). • The DNSP will remove access to this tariff where a premise is found to no longer comply with this criteria.
Technical and Wiring Requirements, including eligible equipment to be connected.	• The premises must have been wired in accordance with the requirements of the QECM at the time of requesting access to the tariff and must comply with jurisdictional metering requirements. • Customers must have 1 or more* eligible equipment (see below), connected under one of the dynamic management mechanisms of **active device management** (refer to QECM 8.10) *Eligible equipment:* i. EVSE (EV Chargers) rated at 7 kW or above, ii. Other equipment that may have been determined by the DNSP • Hard wired equipment only • Any additions and alterations to the electrical installation to enable load control equipment to be installed, as per the QECM requirements, is the responsibility of the customer e.g. contactors and meter wiring.

APPENDIX E – TARIFF TRIAL NOTIFICATION

Ergon Energy Network will undertake trials of storage tariffs to support implementation in future TSS.

Table 27 is the required notification template for a distributor intending to provide sub-threshold tariffs. All fields required unless otherwise specified.

Table 27: Notification template for a distributor intending to provide sub threshold tariff

Distributor	Ergon Energy Network
Total cumulative revenue of all sub-threshold tariffs ($ and % annual revenue requirement (AAR))	Estimate is $75,000 per annum, equivalent to 0.00% AAR per annum across all sub-threshold tariffs.
Confirmation for publication	We confirm that this document contains no commercial or private information and we provide permission for the AER to publish this notification on the AER’s website.

Name of trial	Dynamic Price Storage tariff – SAC (NTCTBA)
Objectives of trial	The objective of this trial is to further develop internal processes to support emerging dynamic tariff needs. The trial will allow for an iterative approach, enabling us to refine the tariff design based on observed outcomes and stakeholder feedback.
Name of trial	Dynamic Price Storage tariff – SAC (NTCTBA)
Retailer engagement	We have undertaken a range of Retailer engagement forums in development of our 2025–30 TSS. This network tariff has been included as part of our engagement approach.
Consumer engagement	We have undertaken a range of customer engagement forums in development of our 2025–30 TSS. This network tariff has been included as part of our engagement approach. We have further engaged with potential customers that have approached Energy Queensland with respect to future storage opportunities.
Expected consumer and/or retailer response	The trial tariff will focus on providing price signals (by charging for export or import at times of constraint) to either incentivise avoidance of import or export at the critical event.
Indicative tariff (structure and pricing)	The indicative structure includes: A Fixed Daily Charge - $/Day Volume Shoulder - $/kWh in the hours of Midnight to 11am, 1pm to 5pm and 8pm to Midnight Daily Volume Off-Peak - $/kWh in the hours of 11am to 1pm Daily Volume Peak - $/kWh in the hours of 5pm to 8pm Daily Critical Peak Period import charge ($/kVA) for imports in notified Critical Peak Import periods, assumed during high network demand periods, to discourage import. Critical Peak Period export charge ($/kW) for exports in notified Critical Peak Export periods above 1.5kW, assumed during low network demand periods, to discourage export.
Links to TSS strategy and Export tariff transition strategy (if applicable)	This trial contributes towards implementation of our TSS strategy and facilitates future export tariff options. Learnings from this tariff trial will help inform the design of a critical peak pricing tariff which we intend to offer as part of the TSS during the 2025-30 regulatory control period pending satisfaction of contingent tariffs arrangements or as part of the subsequent regulatory control period (2030–35).
Forecast revenue ($ and % AAR)	Estimated revenue for the trial is $25,000 per annum, equivalent to 0.00% of AAR per annum.
Trial start date	1 July 2025
Duration of trial	1 July 2025 – 30 June 2026
Potential changes and triggers	We may elect to undertake a Critical Peak Pricing with a temporary modified rate of zero to test both internal and customer processes associated with providing critical peak notifications.
Notification date	November 2024

Name of trial	Dynamic Price Storage tariff – CAC (NTCTBA)
Objectives of trial	The objective of this trial is to further develop internal processes to support emerging dynamic tariff needs. The trial will allow for an iterative approach, enabling us to refine the tariff design based on observed outcomes and stakeholder feedback.
Name of trial	Dynamic Price Storage tariff – CAC (NTCTBA)
Retailer engagement	We have undertaken a range of retailer engagement forums in development of our 2025–30 TSS. This network tariff has been included as part of our engagement approach.
Consumer engagement	We have undertaken a range of customer engagement forums in development of our 2025–30 TSS. This network tariff has been included as part of our engagement approach. We have further engaged with potential customers that have approached Energy Queensland with respect to future storage opportunities.
Expected consumer and/or retailer response	The trial tariff will focus on providing price signals (by charging for export or import at times of constraint) to either incentivise avoidance of import or export at the critical event.
Indicative tariff (structure and pricing)	The indicative structure includes: A Fixed Daily Charge - $/Day Volume Shoulder - $/kWh in the hours of Midnight to 11am, 1pm to 5pm and 8pm to Midnight Daily Volume Off-Peak - $/kWh in the hours of 11am to 1pm Daily Volume Peak - $/kWh in the hours of 5pm to 8pm Daily Critical Peak Period import charge ($/kVA) for imports in notified Critical Peak Import periods, assumed during high network demand periods, to discourage import. Critical Peak Period export charge ($/kW) for exports in notified Critical Peak Export periods above 1.5kW, assumed during low network demand periods, to discourage export.
Links to TSS strategy and Export tariff transition strategy (if applicable)	This trial contributes towards implementation of our TSS strategy and facilitates future export tariff options. Learnings from this tariff trial will help inform the design of a critical peak pricing tariff which we intend to offer as part of the TSS during the 2025-30 regulatory control period pending satisfaction of contingent tariffs arrangements or as part of the subsequent regulatory control period (2030–35).
Forecast revenue ($ and % AAR)	Estimated revenue for the trial is $50,000 per annum, equivalent to 0.00% of AAR per annum.
Trial start date	1 July 2025
Duration of trial	1 July 2025 – 30 June 2026
Potential changes and triggers	We may elect to undertake a Critical Peak Pricing with a temporary modified rate of zero to test both internal and customer processes associated with providing critical peak notifications.
Notification date	November 2024

Name of trial	Secondary Dynamic Price Storage tariff – SAC (NTCTBA)
Objectives of trial	The objective of this trial is to further develop internal processes to support emerging dynamic tariff needs. The trial will allow for an iterative approach, enabling us to refine the tariff design based on observed outcomes and stakeholder feedback.
Name of trial	Secondary Dynamic Price Storage tariff – SAC (NTCTBA)
Retailer engagement	Engagement for this network tariff to be commenced ahead of 1 July 2025.
Consumer engagement	Engagement for this network tariff to be commenced ahead of 1 July 2025.
Expected consumer and/or retailer response	The trial tariff will focus on providing price signals (by rewarding for export or import at times of constraint) to either incentivise import or export at the critical event.
Indicative tariff (structure and pricing)	The indicative structure includes: • Critical Peak Period import reward ($/kWh) for imports in notified Critical Peak Import periods, assumed during minimum network demand periods, to encourage import. • Critical Peak Period export reward ($/kWh) for exports in notified Critical Peak Export periods above 1.5kW, assumed during high network demand periods, to encourage export.
Links to TSS strategy and Export tariff transition strategy (if applicable)	This trial contributes towards implementation of our TSS strategy and facilitates future export tariff options. Learnings from this tariff trial will help inform the design of a critical peak pricing tariff which we intend to offer as part of the TSS during the 2025-30 regulatory control period pending satisfaction of contingent tariffs arrangements or as part of the subsequent regulatory control period (2030–35).
Forecast revenue ($ and % AAR)	Estimated revenue for the trial is $0.00 per annum, equivalent to 0.00% of AAR per annum.
Trial start date	1 July 2025
Duration of trial	1 July 2025 – 30 June 2026
Potential changes and triggers	We may elect to undertake a Critical Peak Pricing with a temporary modified rate of zero to test both internal and customer processes associated with providing critical peak notifications.
Notification date	November 2024

Name of trial	Secondary Dynamic Price Storage tariff – CAC
Objectives of trial	The objective of this trial is to further develop internal processes to support emerging dynamic tariff needs. The trial will allow for an iterative approach, enabling us to refine the tariff design based on observed outcomes and stakeholder feedback.
Name of trial	Secondary Dynamic Price Storage tariff – CAC (NTCTBA)
Retailer engagement	Engagement for this network tariff to be commenced ahead of 1 July 2025.
Consumer engagement	Engagement for this network tariff to be commenced ahead of 1 July 2025.
Expected consumer and/or retailer response	The trial tariff will focus on providing price signals (by rewarding for export or import at times of constraint) to either incentivise import or export at the critical event.
Indicative tariff (structure and pricing)	The indicative structure includes: • Critical Peak Period import reward ($/kWh) for imports in notified Critical Peak Import periods, assumed during minimum network demand periods, to encourage import. • Critical Peak Period export reward ($/kWh) for exports in notified Critical Peak Export periods above 1.5kW, assumed during high network demand periods, to encourage export.
Links to TSS strategy and Export tariff transition strategy (if applicable)	This trial contributes towards implementation of our TSS strategy and facilitates future export tariff options. Learnings from this tariff trial will help inform the design of a critical peak pricing tariff which we intend to offer as part of the TSS during the 2025-30 regulatory control period pending satisfaction of contingent tariffs arrangements or as part of the subsequent regulatory control period (2030–35).
Forecast revenue ($ and % AAR)	Estimated revenue for the trial is $0.00 per annum, equivalent to 0.00% of AAR per annum.
Trial start date	1 July 2025
Duration of trial	1 July 2025 – 30 June 2026
Potential changes and triggers	We may elect to undertake a Critical Peak Pricing with a temporary modified rate of zero to test both internal and customer processes associated with providing critical peak notifications.
Notification date	November 2024

APPENDIX F – PROCESS MAP IN RELATION TO THE DYNAMIC CONNECTION AGREEMENT

Customer Application

1. Criteria for customer eligibility defined.
2. Customers submit an application for a Dynamic Connection Agreement (DCA).
3. Initial assessment undertaken to ensure applicant meets the eligibility criteria.

Dynamic Connection Agreement

1. The Network and Customers to negotiate their dynamic connection agreement to operate within the guard rails of the Dynamic Operating Envelope (DOE) (which will form elements of the Dynamic Flex Storage tariff eligibility and criteria).
2. Network operators calculate the DOE (i.e. permissible import/export limits at various times).

Monitoring and Compliance

1. Through the DCA, the network will have an ability to monitor the storage customers' compliance with the DOE, i.e. the network will control when a customer can import or export into the grid.
2. Identify and address any instances of non-compliance, offering corrective guidance or potential penalties.

Continuous Improvement and Feedback

1. Collect feedback from customers on the DOE and DCA process, compliance challenges, and the tariff structure of the Dynamic Flex Storage tariff.
2. Where it makes sense, adjust our DCA process or tariff structure based on customer feedback.

APPENDIX G – CASE STUDY – DYNAMIC FLEX STORAGE TARIFF

BACKGROUND

In 2024, a large commercial energy user 'ABC Batteries' operating a battery energy storage system (BESS) entered into an agreement with their local distribution network operator 'XYZ Energy' to optimise the use of their storage assets. 'ABC Batteries' sought to maximise its revenue by participating in dynamic energy markets while helping balance the network as the penetration of renewables continued to rise.

'XYZ Energy' introduced a dynamic flex storage tariff tailored for energy storage customers. This tariff was only available to 'ABC Batteries' on the condition they entered into a dynamic connection agreement (DCA) that allowed 'XYZ Energy' to adjust their network export and import limits based on real-time network conditions. This ensured the operation of 'ABC Batteries' would not add to network risk and therefore the risk of future augmentation, (for example 'ABC Batteries' could not act as a load on peak demand days adding to a peak demand event).

KEY COMPONENTS

- XYZ Energy placed guard rails through the dynamic operating envelop and/or the dynamic connection agreement.

IMPLEMENTATION IN PRACTICE

- The DCA stops 'ABC Batteries' from adding to network risk and hence the risk of augmentation, that is, a DCA adds guard rails that essentially protect all customers from paying for augmentation associated with 'ABC Batteries' operation that is not in consideration of the network conditions.
- 'ABC Batteries' has control over how the battery operates within DCA guard rails, that is, 'ABC Batteries' may choose to export at peak times to reduce network stress, or they may choose not to, based on their operational model and the market rates.

RESULTS

1. The Dynamic Flex Storage tariff provides more opportunity for 'ABC Batteries' to participate in markets, while ensuring that participation does not adversely cause costs to other customers. As batteries generally work (for arbitrage) opposite to network load profiles, (i.e. they add load to the middle of the day and add generation to peak demand time) it is expected that 'ABC Batteries' would be rarely adversely impacted in their operation by DOEs.
2. 'ABC Batteries' can realise cost savings by being assigned to 'XYZ Energy's' Dynamic Flex Storage tariff relative to being assigned to a default load tariff structure.
3. By using 'ABC Batteries' BESS to absorb excess renewable energy during times of overgeneration, 'XYZ Energy' can reduce the curtailment of renewable energy generation in the region. This contributes to better integration of renewable energy into the network.

CONCLUSION

This case study demonstrates how a dynamic flex storage tariff tailored for energy storage customers, combined with a dynamic connection agreement, can create mutual benefits for both the customer and the network operator. By allowing the customer to flexibly adjust import and export behaviour based on real-time network conditions, the system maximises revenue for the energy storage operator while contributing to network stability and reducing renewable energy curtailment.

The dynamic connection agreement plays a crucial role in managing network constraints and ensuring the energy storage system operates in harmony with the needs of the network. The success of this model shows the potential for widespread application in energy markets where renewable energy penetration is high, and flexibility in energy storage is essential for maintaining network reliability.

APPENDIX H - AVOIDED TUOS PAYMENTS TO EMBEDDED GENERATORS

Extract from Ergon Energy Network Tariff Guide

Avoided TUOS payments to embedded generators.

Background

In accordance with the NER, Ergon Energy Network is required to pay Avoided Transmission Use of System (Avoided TUOS) to eligible Embedded Generators (EG) in Ergon Energy Network's distribution network. Avoided TUOS payments recognise that energy supplied to the electricity distribution network by the embedded generator would have otherwise been supplied from the transmission network.

Generally, to be eligible for Avoided TUOS payments, EGs must have:

- sought access to Ergon Energy Network's distribution network under Chapter 5 of the NER,
- a generator Connection Agreement with Ergon Energy Network and
- registered or intend to register with AEMO as a Generator Market Participant.

If an exemption applies, or there is no intention for the EG to register as a Participant, we will not make Avoided TUOS payments.

In specific circumstances, Avoided TUOS payments may be allowed to be received by another entity other than the EG (for example where an intermediary is appointed and registered as a Generator under the NER).

Methodology for calculating avoided TUOS

In accordance with the NER, to calculate the avoided TUOS payments for eligible EGs, we:

a) determine the charges for the locational component of prescribed DPPC services that would have been payable by Ergon Energy Network had the EG not injected any energy at its connection point during that financial year.

b) determine the amount by which the charges calculated in (a) exceeds the amount for the locational component of prescribed DPPC services actually payable by Ergon Energy Network, and

c) credit the value from (b) to the EG account.

Reverse flow and net load

Electricity produced by the generator flows back into the transmission network at the transmission connection point (TCP), this is known as excess export, or reverse flow. Where there is reverse flow at the TCP level, that generation does not reduce our net load downstream of that TCP. Accordingly, we remove the reverse flowing electricity from the calculations of Avoided TUOS. This means, our calculation of Avoided TUOS for a particular EG will be based on the difference between:

1) the actual net load at the TCP (and the relevant locational component of prescribed TUOS charges) and

2) the net load at the TCP if the EG was not there (and the relevant locational component of prescribed TUOS charges).

In the event that multiple EGs are connected to the same TCP, and there is reverse flow through the TCP, Ergon Energy Network will apportion the reverse flow attributable to each EG in line with the proportion of each EG's generation into the distribution network. For example, if Generator A exports 100 MWh in a month and Generator B exports 200 MWh in a month, and there is 30 MWh of excess export/reverse flow into the transmission network in that month, we will attribute 10 MWh to Generator A (100/300 x 30 = 10) and 20 MWh to Generator B (200/300 x 30 = 20).

Avoided TUOS calculation We use the below methodology to calculate Avoided TUOS:

1) determine the amount of energy sent out by the EG in the relevant financial year (kWh)
2) convert this to an equivalent amount of energy at the TCP, by adjusting the export energy by the DLF of the EG
3) determine the net generator output (i.e., the generator output that is utilised by the local distribution network, by subtracting the actual metered energy that flows back into the transmission network at the TCP). Where multiple generators are operating in the same local area, the reverse flow is apportioned to each EG using the principles outlined above
4) add the net generation output to the TCP actual metered data for the financial year
5) determine the TUOS that would have been charged if the generator was not connected, by recalculating the customer TUOS usage charges (demand and energy)
6) subtract the actual TUOS payment from the amount calculated in step 5
7) arrange payment of the resultant value from step 6 to the EG (or intermediary).

Payment of Avoided TUOS

Avoided TUOS payments to EGs following the end of the relevant financial year will be made as agreed between Ergon Energy Network and the particular EG (or intermediary) and will generally be remitted in the form of a lump sum payment after 30 June 2023.

Recovery of Avoided TUOS

In accordance with the NER, Ergon Energy Network is able to recover costs associated with Avoided TUOS through TUOS charges in the network tariffs. Where we are to pay an Avoided TUOS payment to an EG, the payment amount is recovered as part of the TUOS volume charges passed through to customers at the same connection point as the EG.

APPENDIX I - SUMMARY OF ALL THE ISSUES RAISED BY THE AER WITH OUR PROPOSED RESPONSE

AER Draft Decision Heading	What the AER Required us to do for the Revised TSS	What the AER encouraged us to do for the Revised TSS	Our responses
19.4.2.1 – Cost reflectivity of Ergon Energy and Energex's Tariffs	Make TOU tariffs the default tariffs for small customers with smart meters including retrospective reassignment for all demand tariff customers (p16,20).		In Section 6.1 we outline our concerns with the AER's decision and explain how we have partially reflected the AER's decision in our revised assignment arrangements. Sections 4.3 and 4.4 of the TSS details our revised assignment arrangements.
		Further customer impact analysis. For example, the percentage of customers better/worse off from moving tariffs or how bill impacts may be mitigated through controlled load (p16).	Chapter 7 includes bill impact analysis associated with movements in default tariffs between years, movements between default tariffs and optional tariffs and impacts of controlled load.
19.4.2.2 – Ergon Energy and Energex tariff assignment policies		Update bill impact analysis to reflect our draft decision that the TOU tariffs be made the default tariffs for smart meter customers (p21).	Section 7.2.2 and 7.2.3 provide details of customer bill impacts for residential and small business customers reflecting the AER's decision on the default smart meter tariff for this customer group.
		Include more supporting information in their proposals including percentages of customers better and worse of as number of affected customers from withdrawn tariffs (p17,21).	Chapter 7 includes information relating to the proportion of customers with lower and higher network bills.
	Include more information on the contingent tariff adjustment to remove tariffs with limited take up during the 2025–30 period (p17).		In response to the AER Draft Decision we have removed the contingent tariff adjustment arrangement for tariffs with limited take-up. Section 1.2 of our TSS includes our revised contingent tariff adjustments.
19.4.2.3 - Tariffs and residential/small business EV owners (including	Include further description of load control arrangements in the QECM insofar as they relate to the TSS's (p22).	Include a copy of the Ergon Energy Network and Energex controlled load tariff supply times within their TSS's rather than in their external Network Tariff Guides (p22).	Sections 4.2 and 6.5 provide further information on load control arrangements and directly respond to AER queries regarding load control arrangements.

AER Draft Decision Heading	What the AER Required us to do for the Revised TSS	What the AER encouraged us to do for the Revised TSS	Our responses
controlled load tariffs)	Further description on the three types of control under the QECM and how they interact with tariffs (p25).		Appendix B provides further information regarding AER queries.
	Further information or examples of circumstances when supply may be turned off or curtailed for customers where an EV charger is on a primary tariff and how they are notified (p25)		Appendix B provides further information regarding AER queries.
19.4.2.3 - Load control for EV owners via the QECM	Provide further description on the flexible load tariff, for example noting that it is only available to those customers whose EV chargers are connected on a dynamic connection (p25).		Appendix C clarifies the arrangement for eligibility and assignment of the residential and small business flexible load tariff.
		Further consultation with stakeholders over distributor control of EV equipment (p23).	We regularly engage with stakeholders regarding this issue through our Network Pricing Woking Group and Demand Management Innovation Working Group.
		Include further information on their contingent tariff adjustments to bring forward introduction of optional demand-only tariffs (p22).	In response to the AER's Draft Decision we have removed the contingent tariff adjustment arrangement for optional demand only tariffs. Section 1.2 of our TSS includes our revised contingent
19.4.3 – Two-way tariffs	Express the basic export level and export charges in kWh rather than in kW for small customers (p26).	Fact sheets and worked examples of how the export rewards and export charges / two-way pricing will apply in practice, including analysis of how customers with different sized solar PV systems could be impacted by two-way pricing (p4).	In Section 6.3 we outline our decision to delay the transition to two-way tariffs having regard to the AER's decision to reject two-way tariff arrangements and default tariff assignment arrangements for small customers.
	Include an explicit export tariff transition strategy, as required by NER, cl. 6.18.1A(a)(2A).	Consolidating all information in an easy-to-read format, for clear compliance with the NER (p29). Provide further detail on how 'dynamic connections' work in practice within their export tariff transition strategy (p26). Provide an export tariff factsheet (p26).	Chapter 6 of our TSS includes our Export Tariff Transition Strategy.

AER Draft Decision Heading	What the AER Required us to do for the Revised TSS	What the AER encouraged us to do for the Revised TSS	Our responses
	Include customer bill impact analysis for LV business customers facing two-way pricing (p26).		Bill impact analysis is no longer required due to the decision to delay further the transition to two-way tariffs.
19.4.3 – Dynamic Connections		Include more information in their revised proposals on the dynamic connection agreement alternative to two-way tariffs, the bill impacts of this option on customers and comparison of this with bill impacts to customers facing two-way pricing and customers facing both two-way pricing and dynamic connections (p28).	Appendix A responds to some of the AER queries regarding dynamic connections noting issues around the alternative application to two-way tariffs in the next period no longer apply.
		Provide description on the longer-term impacts of this arrangement, as we consider flexible export customers (like all exporting customers) should contribute to the recovery of a distributor's costs for delivering export services, commensurate with their contribution to those costs (p28).	Analysis of the longer-term impacts are no longer required due to the decision to delay further the transition to two-way tariffs.
19.4.3 - Dynamic Connections – requirement for customer impact modelling	Include analysis on the network bill impacts to small business or large customers (p30).		Analysis of business impacts are no longer required due to the decision to delay further the transition to two-way tariffs.
19.4.4 – Large Customer Tariffs	Ergon Energy and Energex must offer additional TOU only tariffs for peaky load business customers, such as EV charge point operators (p41).	Include further detail on the impact to customers from changes to their tariffs. (p41).	Information on impacts for customers is provided in Chapter 7.
19.4.4 – Other		Include supporting information on the proposal to remove a kW option from its optional Demand Small (p33).	We respond to the request for additional information in Section 5.4.6 above.
		Include supporting information on the value of avoided TUOS (Ergon Energy only) (p33).	We respond to the request for additional information in Section 5.4.6 above.
19.4.5 – ICC Tariffs		Further description of the ICC tariff class, explaining when customers with installed capacity bellow 10 MVA may be eligible for this tariff class (pg4).	Section 2.2 provides additional information describing the tariff class including eligibility for customers with installed capacity below 10MVA.

AER Draft Decision Heading	What the AER Required us to do for the Revised TSS	What the AER encouraged us to do for the Revised TSS	Our responses
		We encourage Ergon Energy and Energex to include the information in table 1 of their 2023-24 pricing proposals in their Revised TSS's (p41).	We note the AER comment however, the description of the ICC methodology is covered in TSS Section 5.4.2.
		Explain how charges for the ICC class are influenced by the connection assets dedicated to the customer's connection point and how these connection assets were originally funded (p41).	Chapter 8 now includes relevant information on our tariff setting methodology for ICC customers. A summary of our approach to meeting Pricing Principles is covered in Chapter 5 of out TSS.
19.4.6 – Grid Scale Storage Tariffs	Further specificity on how the locational element of tariffs will be implemented (p43).		In section 5.4.4 we outline our engagement on storage tariff issues, noting our concerns with the AER Draft Decision. Section 6.4 provides further information regarding criteria for eligibility and charging parameters. In response to the AER's decision we have moved price based parameters out of our tariff designs and will continue these arrangements in trials. Section 6.8 includes details of these trials.
	What criteria would qualify storage for access to the tariffs and to rewards (p43). How customers may be notified of critical peak events (p43). Whether there is a minimum/maximum number of each type of critical peak event. (p43).	Consider submissions when making final proposals (p43).	In response to the AER's decision we have moved price-based parameters out of our tariff designs and will continue these arrangements in trials. Section 6.8 includes details of these trials.
		Stakeholder feedback on specificity (p43).	Section 5.4.4 covers our engagement on storage tariff issues.
19.4.7.2 – LRMC – estimation methodology		To improve their approach in future iterations of its LRMC methodology by exploring the addition of more location-based elements to their calculations (p45).	Our considerations regarding LRMC can be found in Section 8.3. Our compliance with Pricing Principles and considerations of LRMC are also in Section 5.4.
Tariff Streamlining		Edit text on tariff streamlining, and information on the number	

AER Draft Decision Heading	What the AER Required us to do for the Revised TSS	What the AER encouraged us to do for the Revised TSS	Our responses
		of customers affected by withdrawn tariffs (pg4).	
Engagement		Stakeholder engagement strategies, particularly for customers who may be materially impacted from changes to their tariffs. (pg4).	

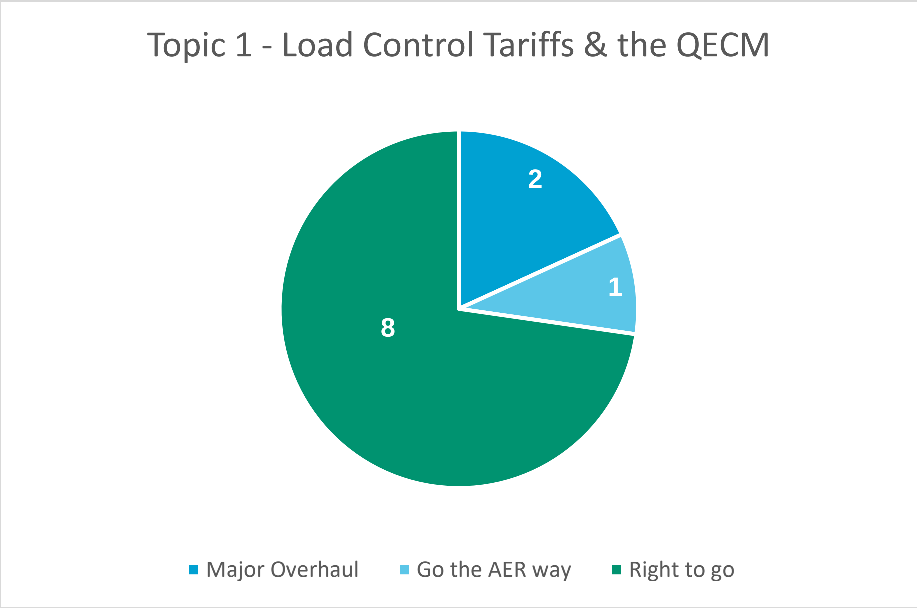
APPENDIX J - NETWORK PRICING WORKING GROUP SUMMARY

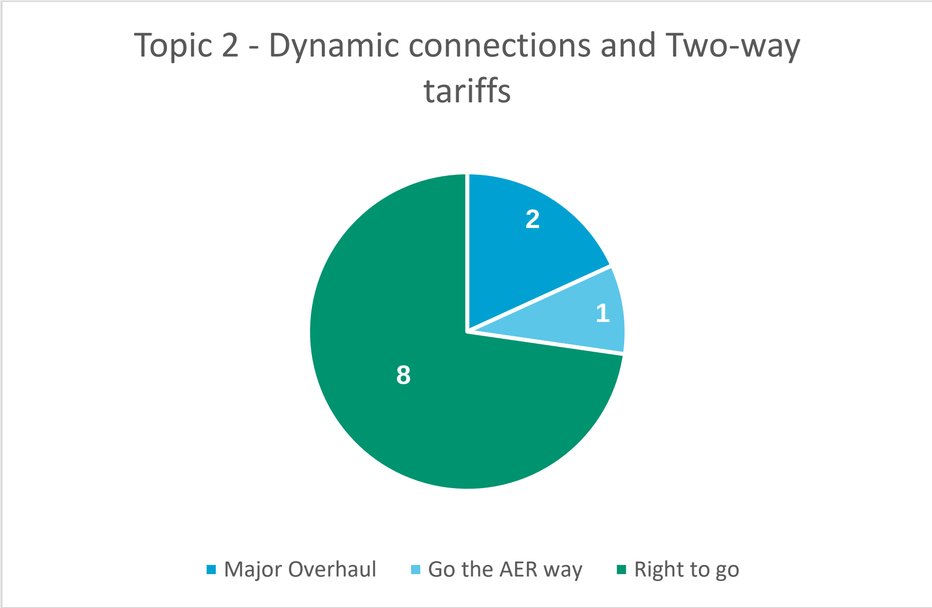
Topic	Load control tariffs and Queensland Energy Connections Manual (QECM)	Dynamic connections and two-way tariffs	Proposed Storage Tariffs and, the level of fixed charges.	TOU Energy Tariffs for customers consuming 100-160MWh p.a.	Demand tariffs and appropriateness as the default tariffs for residential customers
AER Draft Decision	The AER Draft Decision has not approved the proposed flexible load tariffs. Ergon Energy Network and Energex have not adequately described the relationship between the QECM and the TSS. The Revised TSS should include further description of control arrangements that are contained in the QECM, further explanations of the relationship between the QECM and TSS's, and the extent to which control arrangements influence tariff options including the proposed new flexible load tariff.	The AER Draft Decision has not approved the proposed Ergon Energy Network and Energex proposed two-way tariffs as they do not comply with all the requirements in the NER. In order for the TSS to be approved the AER wants our Revised TSS to include an explicit export tariff transition strategy, convert proposed export changes and basic export levels from demand to energy-based measurement, and include network bill impact analysis for small and large businesses proposed to face two-way pricing.	The AER Draft Decision has not approved the proposed Ergon Energy Network and Energex storage tariffs on the basis that they are not compliant with the Pricing Principles. Our Revised TSS should provide further detail on proposed grid-scale storage tariffs, including more detail on the proposed critical peak pricing mechanism.	The AER Draft Decision has not approved the proposed assignment policies because they require Ergon Energy Network to introduce a new optional TOU option for LV business customers consuming up to 160MWh per annum with demand greater than 120kVA but consumption less than 160MWh to contribute to the achievement of the NEO, in particular to Queensland's targets for reducing Australia's greenhouse gas emissions (i.e. its net zero target and its Zero Emission Vehicle Strategy (ZEV Strategy) 2022-2032).	The AER Draft Decision has not approved the proposed assignment policies for residential and small business customers in both Energex and Ergon Energy Network. In order for the TSS proposal to be accepted, Ergon Energy Network must make TOU [energy] tariffs the default tariffs for small customers with smart meters and update network bill impacts accordingly. Additionally, Ergon Energy Network must include more information on the proposed contingent tariff assignment to remove tariffs with limited take-up.
Energy Queensland position for Revised TSS (Oct 2024)	Additional information has been included to assist the AER in understanding the link between connection arrangements customer have with the network and the availability of tariffs based on these connections. We fully agree with the AER that connection	Two-way tariffs transition options were put to customers who accepted a gradual transition but only once other reforms had been bedded down. AER changes to two-way tariffs, combined with significant changes to default tariff arrangements will create instability in the first few years	We do not agree with the AER's Draft Decision that the notice period duration frequency and trigger of proposed critical events is a charging parameter for the purposes of the TSS. These issues have been viewed as dynamic in	The AER's Draft Decision is a departure from our proposed TSS and the NPWG recommendation. The AER gave little or no weight to our considerations or the considerations of the NPWG in this matter. While disappointed with the decision, in order for the assignment policies for large customers to be approved our	In the AER Final Decision for the 2020 to 2025 regulatory control period, the AER's Final Decision was for Energy Queensland to assign TOU demand. From 1 July 2025 the TOU Energy tariff will be the default tariff.

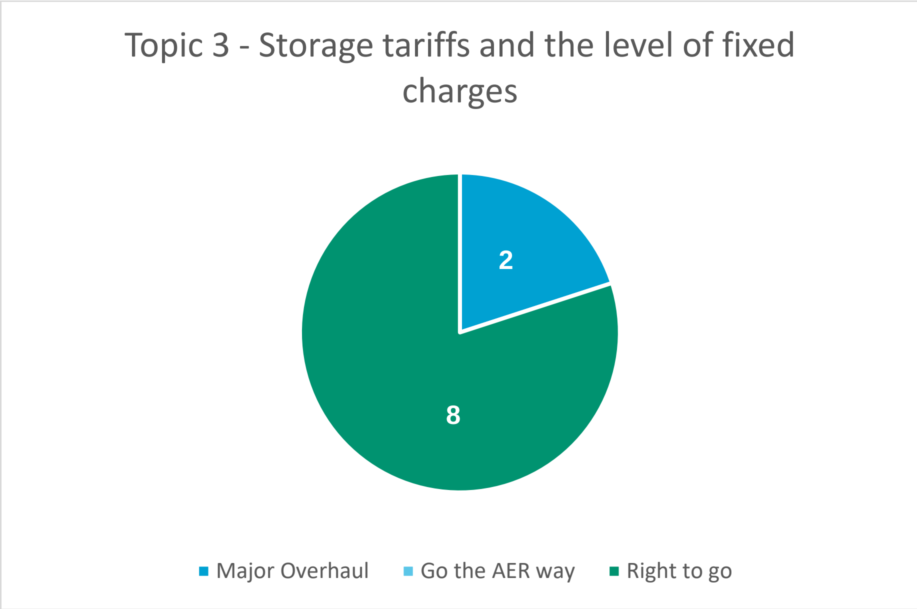
Topic	Load control tariffs and Queensland Energy Connections Manual (QECM)	Dynamic connections and two-way tariffs	Proposed Storage Tariffs and, the level of fixed charges.	TOU Energy Tariffs for customers consuming 100-160MWh p.a.	Demand tariffs and appropriateness as the default tariffs for residential customers
	arrangements and technical standards relating each connection are outside its remit and should not be part of the AER Draft Decision. We will no longer change tariff structure arrangements for the residential flexible load tariff from the TSS following discussions around the billing difficulties and the potential for future non-compliance	of the next regulatory control period. There is considerable confusion and uncertainty around the ability of the retailer to pass these tariffs on. The AER's Draft Decision changed the current assignment arrangement due to lack of customer comprehension and understanding make any introduction of charges for export in the 2025-2030 regulatory control period difficult to justify.	nature in previous decisions and the AER has not sought to embed them in a static five year document. We will exclude the dynamic price storage tariffs from TSS and continue as trial tariff only. We are proposing to include a dynamic flex storage tariff in TSS with the removal of pricing components.	Revised TSS will include a TOU Energy tariff for large customers with a peaky load >120KVA consistent with the AER draft decision.	We are proposing to not reassign any existing customers on the TOU demand tariff (current default tariff) to TOU Energy tariff (new default).
NPWG response to Energy Queensland thinking for Revised TSS (@Oct 2024)	The clear majority of the NPWG feel that the right approach to moving forward with Load control tariffs is to continue with the position Energy Queensland has adopted post Draft Decision. This included support by the NPWG for Energy Queensland providing further explanation where available and including references to other information and documentation including the QECM. There are a number of members of the NPWG who are concerned that	The NPWG, whilst acknowledging that the AER's decision to decline the proposed tariffs was on the grounds of them not complying with the NER the requirements that the AER are asking Energy Queensland to meet are likely to result in Energy Queensland pushing the introduction of these tariffs till 1 July 2028. The NPWG is disappointed that there is a further delay in introducing these tariffs which we believe are foundational to the energy transition. This delay will perpetuate and expand the ongoing cross-subsidies between solar and non-solar customers and	9 out of 11 NPWG members consider that Energy Queensland should proceed with its proposed response. A minority suggest that deferral of storage tariffs will not be helpful, and for certainty, storage tariffs should be included in the TSS in preference to further tariff trials. NPWG members are concerned that storage tariffs are cost reflective and do not introduce inequities for other customers. It is not the AER's role to use the	8 out of 11 members support the Energy Queensland proposed response. 2 of 3 members who do not support the response, support Energy Queensland proposal in principle. However they recognise Energy Queensland will not be able to influence the AERs decision given the AER approach to measuring emissions benefits and their desire for uniformity across the other networks. All NPWG members support greater transparency from the AER on the efficiency and equity trade offs it had to make in coming to its final decision.	9 out of 11 NPWG members supported the proposed Energy Queensland response to the Draft Decision. There was concern that the AER's decision will result in less equitable and efficient outcomes for customers. Laying the right foundations is pivotal to the transition, and to having these as future focused and focused on what we think are the right foundations to underpin the transition and unpick cross subsidies and not create new ones. Moving to volumetric charging means that customers with large solar or battery installations are charged less

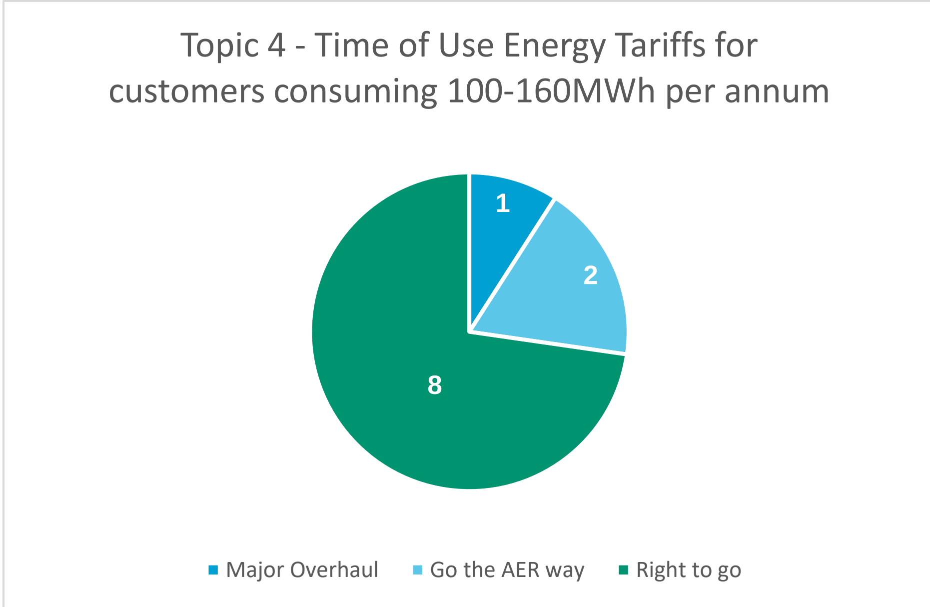
Topic	Load control tariffs and Queensland Energy Connections Manual (QECM)	Dynamic connections and two-way tariffs	Proposed Storage Tariffs and, the level of fixed charges.	TOU Energy Tariffs for customers consuming 100-160MWh p.a.	Demand tariffs and appropriateness as the default tariffs for residential customers
	rebates offered in return for load control may not reach consumers and therefore it does not send a price signal. The redesign of the customer rebate (from one off to over time) on this issue by Energy Queensland is appropriate. There are concerns that there could be conflict between QECM and the historical connection agreement that should be investigated to ensure retailers can assign this network tariff to customers that the tariff may apply to	potentially introduce new cross subsidies as new technologies are purchased by households such as EV and home battery storage for example. Furthermore, Energy Queensland's response to AER's Draft Decision, to further delay the introduction of two-way tariffs in Queensland is inconsistent with AER's decisions made in the NSW networks, which allowed export pricing from 1st July 2024, which is the first year of the regulatory control period for NSW. The failure to have two-way pricing i.e. export pricing means there is a lack of a pricing signal to underpin new market offerings such as dynamic connection agreements. We agree Energy Queensland should provide more detail of consumer impact as a result of Energy Queensland's decision to further delay following the AER Draft Decision.	TSS to impose non-cost reflective tariffs to support a particular technology. That is the role of governments.		than customers who do not, for the same peak demand. The cross subsidy remains. It is difficult for NPWG to provide a response to the AER draft when it is unsure of how the AER has weighed all the factors including political and media commentary. The NPWG is concerned about costs and operational impacts on DNSPs and retailers and potential customer confusion for those customers moved from TOU demand tariffs to TOU energy tariffs. The NPWG expects that customers who are unhappy with demand tariffs will soon be able to move to a flat retail tariff regardless of their network tariff. A key point is that information needs to be provided directly by Energy Queensland to consumers. We need to improve network utilisation and that means consumers need to understand not just retailers.

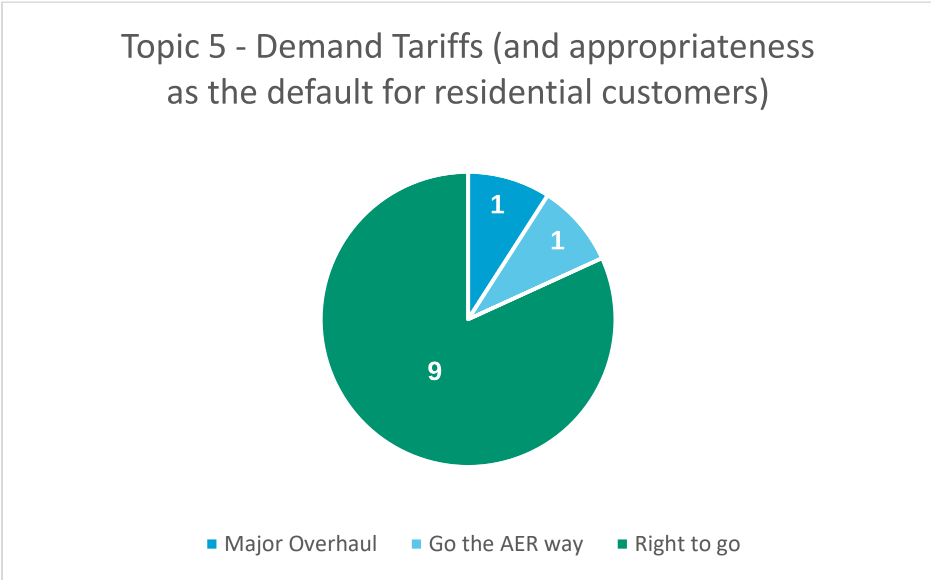
Figures below represent the individual NPWG members votes on each of the issues presented from our customers and stakeholders.






Topic 3 - Storage tariffs and the level of fixed charges
2
8
Major Overhaul
Go the AER way
Right to go


Topic 4 - Time of Use Energy Tariffs for customers consuming 100-160MWh per annum
1
2
8
Major Overhaul
Go the AER way
Right to go


Topic 5 - Demand Tariffs (and appropriateness as the default for residential customers)
1
1
9
Major Overhaul
Go the AER way
Right to go

APPENDIX K – OUTLINE OF HOW THE QECM RELATES TO OUR FLEXIBLE LOAD TARIFFS

QECM device management Option	DNSP management of consumer energy resource	Interaction with tariff	Load management arrangements	Typical application(s)	Customer information
Controlled tariff via network device (QECM 9.2, 10.6)	Via network device installed, in customer switchboard, using AFLC[65] signalling technology. Note AFLC is available in most areas. In some fringe of network and isolated communities where AFLC is not available, a load control relay with a timeclock (set on and off times) is utilised.	Small customers choosing this device management option in the QECM are subject to controlled load arrangements eligible for secondary load control network tariffs in Ergon Energy Network: • Economy / Volume controlled OR • Super Economy / Volume Night Controlled.	The QECM refers to conditions for the secondary load control tariffs outlined in Network Tariff guide. These conditions specify the following: • a minimum of 18 hours (Economy / Volume Controlled) & 8 hours (Super Economy / Volume Night Controlled) of supply respectively. • actual supply interruptions vary by location and time of year and are typically during the evening peak periods and early mornings. There is no notification of actual switching.	Suitable for customers wanting to access cheaper rates on a secondary load control tariff and avoid exposure to time-varying signals in primary network tariffs.	Generation information on secondary load control tariffs – click here Customer information on EV changing options – click here Installer focussed information on EVSE – click here

QECM Device Management Option	DNSP Management of CER	Interaction with tariff	Load management arrangements	Typical Application(s)	Customer Information
Basic active management via network device (QECM 8.10.5, 10.6)		This mechanism is nominally most suited on any primary tariff at a premise supplied at 100A/phase or less but is agnostic as to which tariff it is applied to. Small customers choosing this device management option in the QECM, to manage their EVSE, are eligible for the optional Flexible Load Tariff.	The QECM refers to conditions for primary load control tariffs outlined in Network Tariff guide. These conditions specify the following: Minimum 18 hours of supply (in practice, the switching of these dedicated load control channels is limited to extreme load situations) (i.e. short duration for a small number of times per year) in network areas impacted by a network constraint. There is no notification of actual switching.	This connection allows for a dedicated EVSE charger to be installed on a primary tariff, so that customers can charge their EV from their solar PV system, and/or take advantage of TOU tariffs. ON/OFF control of charging is delivered.	
Dynamic connection (for EVSE) (QECM 8.10.4)	Via communication between the DNSP's SEP2 server and the customer device; a compliant gateway device; or a 3rd party cloud proxy (platform). Does not involve any network equipment – customer is responsible for installing any necessary hardware or software to enable the connection to the SEP2 server.	This mechanism is nominally most suited on any primary network tariff at a premise supplied at 100A/phase or less but is agnostic as to which tariff it is applied to. Small customers choosing this device management option in the QECM are eligible for the optional Flexible Load Tariff. The QECM refers to conditions for primary load control tariffs outlined in Network Tariff guide (see above)	Under a dynamic connection (for EVSE), signals can be sent to temporarily vary the capacity at which the EV charger can operate (full curtailment still allows 1.5kW of import), depending on the demand on the electricity network. These signals are known as the DOE. Power supply to the dedicated EV charger will only be reduced if the local network (down to Distribution Transformer) is under significant stress. There is no notification of actual switching.	This connection allows for a dedicated EVSE charger to be installed on a primary tariff, so that customers can charge their EV from their solar PV system, and/or take advantage of time-varying signals in primary network tariffs. As the load management control is to ramp down (rather than ON / OFF), this may be more attractive to some EV owners.	

QECM Device Management Option	DNSP Management of CER	Interaction with tariff	Load management arrangements	Typical Application(s)	Customer Information
Emergency Backstop (8.10.2)	Use of AFLC based Generation Signalling Device (AS 4755) connected to inverters.	No interaction with tariffs – Backstop is a requirement of Connection Standards for new PV systems 10kVa and above.	Provides capability for AEMO instigated curtailment of solar generation in emergency contingency events.	Requirement of new and upgraded PV systems after February 2023	For more information on the Emergency Backstop – click here. .
PeakSmart (8.10.3)	Use of AFLC based, DNSP owned demand response enabling device (DRED) to reduce output of residential a/c	No interaction with tariffs – PeakSmart is a voluntary program, involving a one-off customer incentive payment.	PeakSmart is typically activated several times per year, during summer peak periods.	Voluntary program available since 2012	For more information on PeakSmart – click here.