Ergon Energy TSS Explanatory Notes 2020 - 2025

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Contents

1 BACKGROUND

These Explanatory Notes accompany our 2020-25 Tariff Structure Statement (TSS) submission to the Australian Energy Regulator (AER) on 10 December 2019.

The Explanatory Notes provide detailed information on our proposed network tariff classes, network tariff structures and charges for the 2020-25 regulatory control period and how we comply with the National Electricity Rules (NER) and distribution pricing principles. It also provides us an opportunity to comment on our network tariff strategy and how this will shape future network use.

1.1 Guide to these Explanatory Notes

This Explanatory Notes document provides both support and context to our Revised TSS, which outlines our proposed tariff classes, tariff structures, charging parameters and indicative tariff levels, and demonstrates compliance with the distribution pricing principles.[1]

The development of the 2020-25 TSS has coincided with a period of significant change in the way in which customers use our distribution network and the expectations customers have of the network services we provide. To ensure our network tariffs remain relevant into the future, we need to start considering the future network tariff structures that will be required to meet the evolving needs and expectations of our customers.

We anticipate that future network tariffs will be capacity based. Capacity based tariff structures are very relevant in an environment where the low voltage network is evolving to become an active network that will, for example, support greater levels of rooftop solar and other forms of home load management technologies and markets (e.g. batteries, peer-to-peer trading).

However, we also recognise that capacity based tariffs are a significant evolution from the suite of network tariffs currently on offer, particularly to small customers who are unfamiliar with them. Given this situation, we consider it important to start taking customers on a journey towards these more cost reflective future tariff structures during the 2020-25 regulatory control period.

Since our TSS submitted on 14 June 2019, we have developed three network tariff options for our residential and small business customers (in the Standard Access Customers (SAC) tariff class) to assist their transition to future capacity based cost reflective tariffs.

We have also extended the availability of broad based load control tariffs to small and large business customer by developed primary and secondary load control tariffs. During the TSS engagement in 2018-19 the value of load control was noted by a number of our customer segments, and these tariff options seek to incorporate this feedback while offering customers additional choice and control options that suit their particular needs. We also used the learnings from our recent load control tariff trial with the agricultural sector to inform the tariff's application in the business sector.

1.2 How to read this document

The remainder of the Explanatory Notes is set out as follows:

- Section 2 provides a strategic view of network tariff options and the need to identify a relevant platform to ensure we maintain the momentum of our proposed network tariff reforms throughout the 2020-25 regulatory control period .
- Section 3 examines the drivers of network tariff reform within a rapidly developing energy market landscape. The section also explains how the proposed network tariffs and tariff

[1] National Electricity Rules, Chapter 6, Clause 6.18.5

structures have been developed to complement our network planning and Demand Management (DM) strategies.

- Section 4 outlines the alignment of EQL's network tariff and corporate strategy. It also notes the interaction between the network tariff strategy and the customer strategy.
- Section 5 presents our tariff classes, individual tariffs and associated tariff structures that will be available over the 2020-25 regulatory control period.
- Section 6 discusses the rationale for the standard control services (SCS) tariff classes, tariff implementation and tariff structures.
- Section 7 discusses our compliance with the distribution pricing principles.
- Section 8 presents our alternative control services (ACS) and associated pricing mechanisms for the 2020-25 regulatory control period in alignment with the AER's Framework and Approach (F&A).
- Appendix A sets our selected stakeholder responses.

1.3 Next steps and on-going consultation

We submitted our initial TSS in January 2019. Our proposed TSS was supported by an Explanatory Notes document which outlined our emerging capacity strategy and associated proposed network tariffs and tariff structures.

An updated June 2019 TSS consolidated the current state in our capacity tariff suite development and the initial positions presented in January 2019. In preparing our Revised TSS submission, we have incorporated received feedback through consultation we have undertaken since January 2019 and responded to the AER's Draft Determination released in October 2019. Our Revised TSS maintains the strategic framework in which the current tariff strategy has been developed while responding to customer feedback and ensuring TSS compliance.

The AER will also consult on its Draft Determination and our Revised TSS before publishing its Final Determination by April 2020. We encourage our communities and customers to make submissions to the AER as part of its consultation processes.

After the AER publishes its Final Determination, we will prepare our distribution network charges for the 2020-21 regulatory year, commencing 1 July 2020.

In the meantime, we will continue to engage with our customers and other stakeholders on this TSS, including through our Customer Council and our website, www.talkingenergy.com.au, where all of our existing consultation material is available. Questions can also be directed to us via tariffs@energyq.com.au.

2 OVERARCHING TARIFF STRATEGY

EQL's overarching tariff strategy is to establish a suite of network tariffs that promote efficient network usage, which in turn should facilitate efficient network investment decisions. In so doing, our tariff suite is directed to supporting our network planning decisions. In addition, recognising that there are currently practical limitations to implementing cost reflective tariffs across all our customers, particularly availability of digital metering[2] for residential customers, EQL has developed and improved several complementary non-tariff tools e.g. air conditioning load control. These non-tariff tools have the potential to shift customers' energy consumption from peak to off-peak periods in a targeted way to address locational network constraints, without compromising customers' lifestyle, as well as providing customer rewards. This mix of tariff and non-tariff instruments will enable EQL to flexibly manage its network capacity having regard to making future efficient network investment decisions.

However, throughout the consultation on our TSSs for the 2020-25 regulatory control period, we have heard how customers are now choosing to use our network in many different ways. Combined with emergent technology shifting network utilisation patterns, our existing tariffs no longer enable a fair recovery of network costs or provide the flexibility and choices expected by our customers.

In the longer term, we anticipate an increase in the relevance of capacity-based tariffs in support of emergent technology and new customer needs, supported by load control tariffs and broad based and locational demand management programs.

Consequently, we consider that the TSS for the 2020-25 regulatory control period needs to start that transition, catering for diverse customer needs through offering a mix of cost reflective tariff options that include demand and time of use (ToU) energy tariffs, and simple and attractive load control tariffs. Customers assigned to cost reflective network tariffs will benefit from the pass through of substantial revenue reductions in the first year of the regulatory control period. EQL will support our customers in this transition.

2.1 Mandate for Tariff Reform

The structures of most of our network tariffs were developed in the early 1990s - a period when distribution networks supported a one-directional supply of electricity from centralised generators to customers, and customers accessed the network in the same fashion.

Technology advances (like solar panels, home batteries, digital meters), the emergence and increased adoption of energy intensive appliances (like air conditioners and pool pumps), transport advances (such as electric vehicles), a growing population, greater household incomes, regionalisation, the emergence of aggregators and technology platforms where energy can be traded, and (generally) higher standards of living, all contribute to the current situation whereby customers are no longer accessing and utilising our electricity networks the way they used to.

Also, as a customer-centric organisation, we listen to our customers, who, in relation to our networks and the cost to use our networks, are telling us that:

- They expect us to ensure equity of access to electricity
- They support tariff reform and greater cost reflectivity
- They want greater choice in their tariff options and control over their electricity supply

[2] The term 'digital metering' used in these Explanatory Notes, refers to communications enabled Type 1-4 meters.

- They are concerned about affordability, and
- They need us to keep our tariffs as simple as possible.

Customers are of the view that our existing legacy network tariffs embody cross-subsidies, in many cases they do not reflect the true cost of supplying electricity (especially in periods of peak demand), and there are few choices available. However, small customers are also concerned about cost reflective tariffs and have acknowledged the fact that the tariff reform journey may require intermediate steps and transition periods before reaching the desired outcomes.

We have listened to this feedback and developed a tariff suite for the 2020-25 regulatory control period that we consider reasonably addresses our customers' tariff requirements.

2.2 Our current position (2020-25 TSS)

Our tariff reform journey started in 2015 with ToU energy and demand tariffs progressively being made available to our residential and business customers. These tariffs have had limited mass market adoption, in part due to the majority of small customers having basic meters and the limited exposure of these tariffs to the retail market.

Our 2020-25 TSS reflects the following actions we propose to take in advancing towards a cost-reflective tariff future. We propose to:

- Introduce a suite of new demand and ToU energy tariffs for residential and small business customers (Standard Asset Customer (SAC) tariff class)
- Adopt a narrower non-seasonal evening peak window of 4-9 pm in all our new demand and ToU energy tariffs
- Change our tariff assignment policy for the SAC tariff classes to enable a more rapid take up of cost reflective tariffs while managing customer price impacts
- Provide increased incentives for customers to take up existing and new load control tariffs, including offering three new load control tariffs to business customers.
- Undertake capacity tariff trials to inform 2025-30 tariff reform.

2.3 Future State – Capacity Based Tariffs (2025 and beyond)

The drivers of network investment are changing and expanding. This expansion includes the challenge to integrate large amounts of distributed energy resources (DER) into the network, investment to maintain network voltage and power quality performance as well as declining levels of traditional augmentation where network capacity is exceeded. Our tariffs need to develop in line with these changes and remain relevant as the electricity supply market continues to evolve.

Under this scenario there would be a bias towards the network charging on the basis of providing adequate capacity rather than charging on the basis of signalling network peak demand constraints. The peak demand response remains an important consideration but accommodating these new business drivers needs to be integrated into our future network tariff development.

We plan to progress capacity based tariff trials for residential and small business customers during the 2020-25 regulatory control period.

2.4 Key elements of our 2020-25 tariff strategy

Integrating network cost drivers into cost reflective network tariff structures that are compliant with the NER leads to ToU demand or ToU energy network tariffs. Currently almost all of our residential and small business customers are assigned to two-part network tariffs that consist of a daily charge plus a rate for energy consumption irrespective of when the consumption occurred.

In the 2017-20 TSS, we introduced demand tariffs to residential and small business customers as part of complying with the new NER requirements. Key market feedback on these demand tariffs has been that:

- Customers were challenged by the concept of demand, particularly when overlaid with other complexity in language and determining billable quantities
- Retailers found it a challenge to get customers comfortable with these ToU demand tariffs and to adopt them, and
- Stakeholders struggled to communicate this reform as a step forward

Despite the challenges, the NER has firmly put the electricity market on a pathway where networks need to be setting prices of distribution network services on a basis that reflects the Long Run Marginal Cost (LRMC) and that signals optimal and efficient usage of the network.

Successful implementation of our 2020-25 network tariff strategy will:

- Reduce cross-subsidies between customers
- Minimise uneconomic investment in solar PV and other emerging technologies
- Improve network capability to manage network cost issues through load management
- Contribute to an increase in network utilisation through shifting energy consumption from peak periods to off-peak periods, including through implementation of new load control tariffs
- Delay or defer network investment in augmentation, power quality and voltage management, and
- Maximise the number of residential and small business customers on cost reflective tariff structures, recognising that larger customers generally already face such tariff structures.

2.5 Pace of tariff reform

In considering the implementation of our network tariff strategy, we have taken into account the market conditions, the availability of digital meters to residential and small business customers, the impact of tariff reform on customers and feedback provided by stakeholders as part of our engagement process. Stakeholders have noted timely access to digital metering (or equivalent technology) as a barrier to the uptake of cost reflective tariffs. They have also confirmed the need for customer education and information as key elements to accelerate network tariff reform.

For these reasons and in particular because of the potential customer impacts from moving existing customers to cost reflective tariffs, we will offer a new transitional demand tariff to manage the price impact for new customers assigned to this tariff. This assignment approach will allow these customers to evaluate all of their tariff choices, including an alternative simple time-of-use energy tariff and a traditional demand tariff.

2.6 Market Conditions

The full potential of our network tariff reforms will be achieved where the network tariff signals are matched with the provision of services to customers and the availability of a range of enabling technologies. The introduction of cost reflective (demand or energy based) network tariffs will enable customers to benefit from new technological developments, product innovation and behavioural changes. Figure 1 illustrates the broader market environment in which network tariff reform is only one element of customer value.

Figure 1 - Market environment

We recognise that the implementation and success of network tariff reform will only happen through a coordinated market approach and the active engagement of a wide range of stakeholders, including electricity retailers, our customers, customer advocacy groups and government agencies. It is also reliant on the uptake of new technology, primarily digital metering.

We acknowledge that the design of network tariffs requires careful consideration to avoid signalling peak demand too sharply leading to bill shock and are actively mitigating this through the tariff options we have proposed, in particular the calibration of the transitional demand tariff for premises with digital meters. For some residential and small business customers, demand tariff structures may be unfamiliar and difficult to understand. Consequently, a ToU energy tariff will be made available as an alternative tariff option, which will include evening (peak), night (shoulder) and day (off peak) energy charges and a daily fixed charge. Our stakeholder engagement indicates that such a tariff is likely to be easier for some residential and small business customers to understand.

3 DRIVERS OF TARIFF REFORM

3.1 A changing Queensland energy market

The energy market in Queensland (and regions of the National Electricity Market (NEM) in general) is undergoing significant transformational change. The market has transformed from an environment that was dominated by central large-scale, synchronous power plants, with passive consumption, to an environment with multitude of resources (e.g. rapid increase of distributed energy resources (DER) such as distributed and rooftop solar, storage, load management) and emerging technologies. With this transformation, several operational challenges arise identified by AEMO below.[3]

System change	Observations	Challenges
Supply mix	• More variable renewable energy • Less dispatchable generation • Older generation resources	• Increased variability and uncertainty in the generation resource mix • Increased reliance on AEMO directions
Electricity demand	• Higher ramps for peaks • Lower minimum demand • More active consumers • More DER	• Increased variability and uncertainty in demand • Erosion of baseload generation • Increased ramping requirement

The key drivers contributing to the changing energy system with direct impacts on EQL's distribution networks include:

- Solar photovoltaic (PV) installations
- EVs
- Battery-based energy storage systems
- The development of an aggregator market offering energy trading services to our customers.

It is important to note that the increasing penetration of new energy technologies is being driven both by markets (including the rapidly declining cost of new energy technologies), as well as Queensland Government policy initiatives directed towards increased take up of these new technologies.

Solar PV

Queensland has the highest amount of rooftop solar PV capacity and installations in the country.[4] The uptake of rooftop solar PV systems in Queensland began to rise significantly in 2010, growing from around 60,000 installations in September 2010 to approximately 550,000 systems by the end of January 2018. The cumulative capacity at just over 2,000 MW in early 2018 was larger than any individual conventional power station in the state (the biggest being Gladstone at 1,680 MW). Residential dwellings (including flats and apartments) accounted for 29 per cent of the total systems installed.

Figure 2 shows the cumulative uptake of solar PV in Queensland since 2007.

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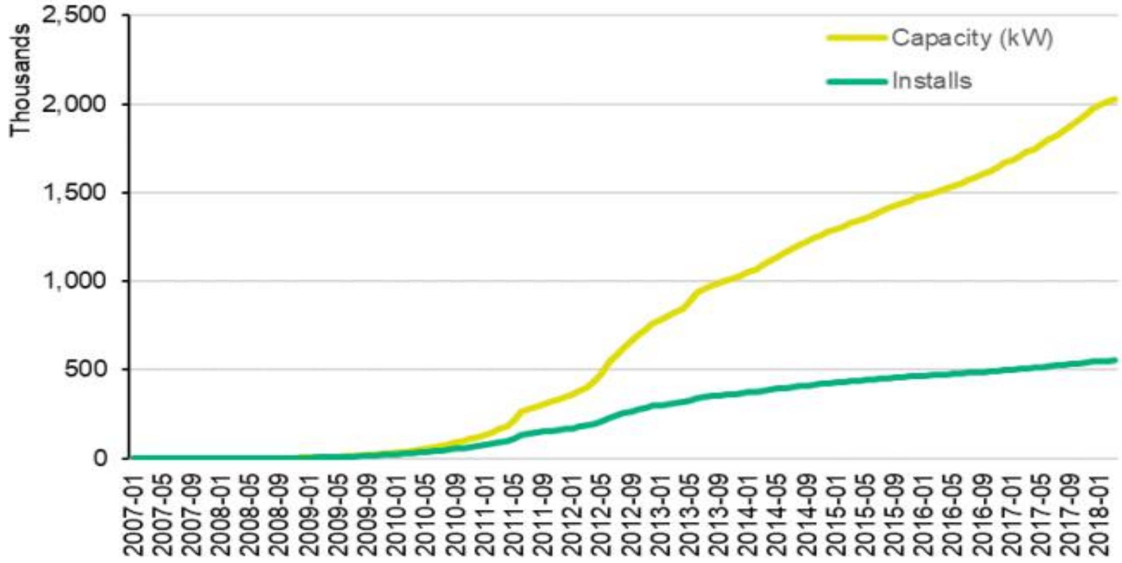
[3] AEMO (2018), AEMO observations, Operational and market challenges to reliability and security in NEM
[4] Green Energy Markets (2018). Renewable Energy across Queensland's Regions.

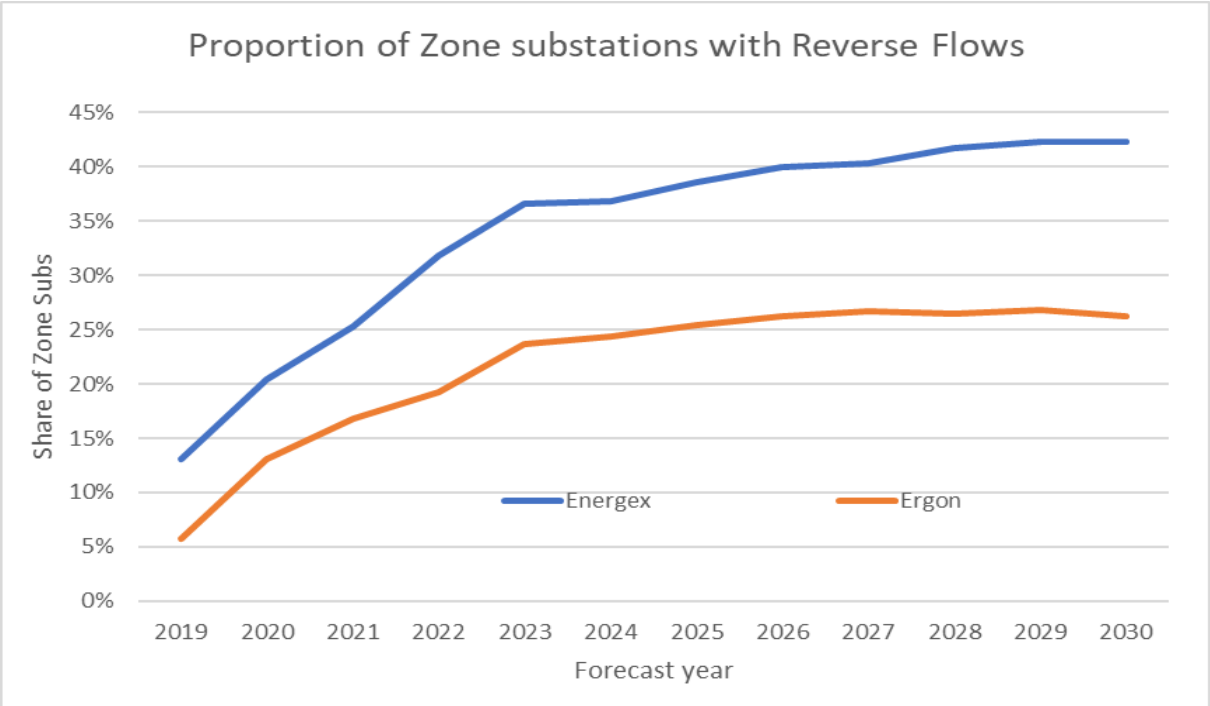
Figure 2 - Cumulative uptake and capacity of solar rooftop PV in Queensland[5]



Furthermore, projections suggest that by 2019-20, electricity generated from solar rooftop PV systems in Queensland will displace 3,805 GWh of electricity generated from other sources, and by 2034–35 it would displace 8,403 GWh.[6]

This significant increase in solar PV capacity is having a profound effect on energy flows on our networks. Currently, there are about 60 substations with reverse flow across Energex's and Ergon Energy's networks, with the majority being residential substations. We project that substations with reverse flow will exceed 200 over the next 10 years, which will lead to a substantial change in network operation.

Figure 3 Forecast of zone substations with reverse flows on Energex and Ergon Energy networks



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[5] Green Energy Markets (2018).

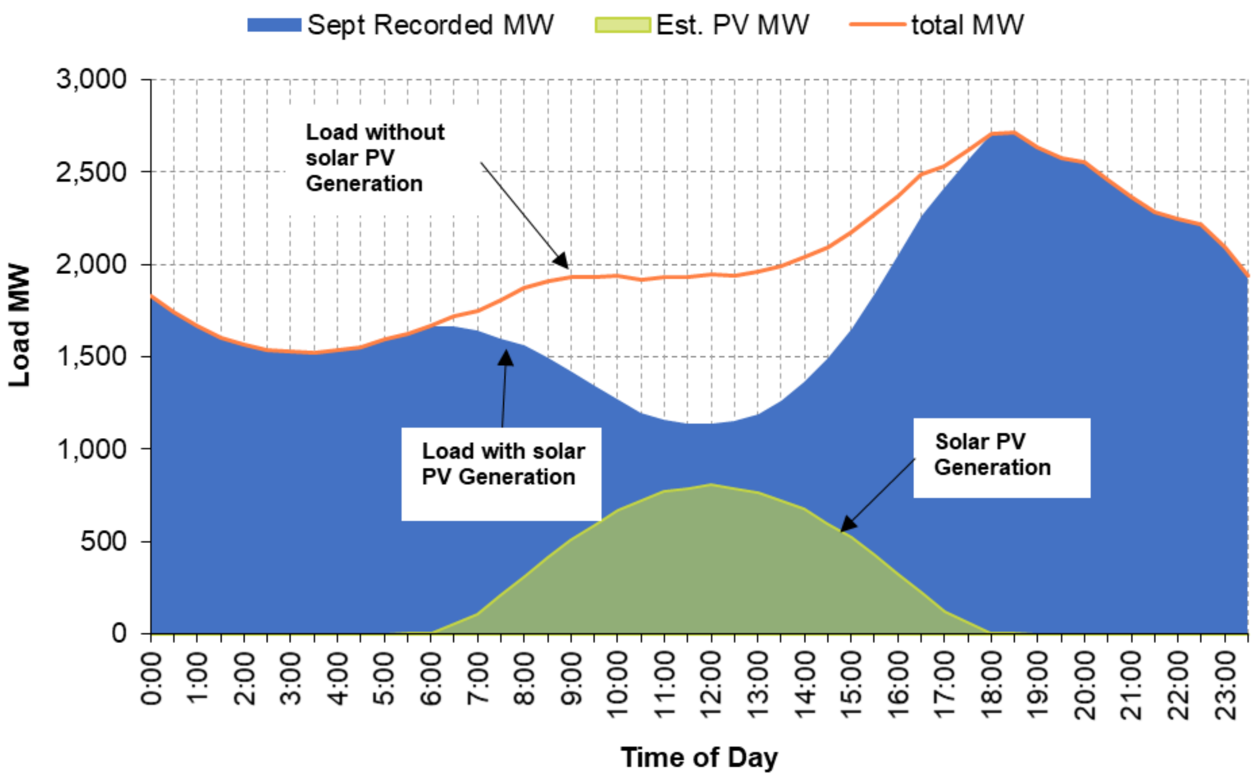
[6] ACIL Allen Consulting (2015). Electricity market modelling. Report for the Queensland Productivity Commission, Brisbane.

Low and negative loads exacerbate voltage control issues on our networks. To date, we have been able to leverage voltage regulation at the transmission connection point to limit the need for downstream remediation, but increasingly this will not be possible as the transmission network runs out of transformer tap or 'buck' range.

Further, this short-term mitigation does not address the bigger issue that the increasing penetration of solar PV (and other DER) on our networks will require enhancement of monitoring and control functionality to provide for connection of DER within the safe technical range of each network's capacity and to allow for optimising the performance of the integrated network with its connected devices. The implementation of cost reflective tariffs at the residential level is one of the complementary tools we intend to use to attempt to mitigate the size of this future investment requirement, including through their potential influence on customers' future consumption profiles and the resulting energy flows at substations.

In addition to reverse energy flows at substations, Figure 4 below shows the impact of solar PV on Energex's minimum system demand on 8 September 2019. The figure indicates that the impact of solar PV output will soon rival the size of the load on minimum demand days at the system level, again indicating the potential for negative energy flows at the substation level of our networks.

Figure 4 - Minimum demand on Energex network in September 2019



More generally, Figure 4 indicates the hollowing out of demand on our networks during the middle period of minimum demand days, which has driven the solar sponge initiative incorporated into our proposed cost reflective tariffs for residential customers.

The growing uptake of solar PV has been largely driven by state government initiatives, including Ergon Energy's and Energex's relaxed connection requirements making it easier and cheaper to connect solar PV or battery energy storage systems to the grid. The Queensland Government has set a target of one million rooftops or 3,000 MW of solar PV of all scale in the state by 2020.[7] To reach its solar target, the government recently delivered a comprehensive package of initiatives to increase and support the use of solar PV, including:

A range of changes to the regional feed-in tariff and monitoring arrangements in South East Queensland, such as:

- introducing an optional time varying feed-in tariff (T-FiT);
- expanding regional feed-in tariff eligibility to include systems up to 30 kilowatts in size; and
- continued monitoring of feed-in tariffs in South East Queensland by the Queensland Competition Authority.[8]

- Amending the Electricity Regulation 2006 to align Queensland's distribution network voltage limits with Australian and international best practice standards.
- New voltage limits (from 240 volts +/-6% to 230 volts +10/-6%) so electrical appliances and equipment will operate more efficiently at lower voltages.
- Implementing the Advancing Clean Energy Schools (ACES) Program, which is a $97 million investment to reduce energy costs across state schools through solar and energy efficiency measures.
- Implementing the solar for public housing trial, which will install solar panels in trial locations to deliver up to 6 megawatts of solar on up to 4,000 government-owned, detached houses.[9]
- Implementing the Solar 150 initiative, in collaboration with the Australian Renewable Energy Agency (ARENA), which will support up to 150 megawatts of solar power generation in Queensland.[10]

Battery storage

Until recently storing electricity was not commercially viable, however emerging technologies are making storage increasingly attractive. For smaller customers, storage offers opportunities to store surplus energy from solar PV systems and draw on it when needed, reducing their grid demand. The wider use of cost reflective tariffs may make storage more attractive by creating incentives to charge batteries during low cost periods and use stored power when prices are high.

The already significant presence of rooftop solar in Queensland is already having a significant impact on the Energex and Ergon Energy network load profiles, i.e. creating very low loads, at accompanying low prices, when solar output is highest, and a very high and fast ramp in the afternoon. AEMO observed that current arrangements do not fully optimise the value that could be delivered by some resources, particularly price-responsive demand and fast responding storage

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[7] Department of natural Resources, Mines and Energy (2019). A solar future: powering Queensland's renewable energy industries. Available from: https://www.dnrme.qld.gov.au/energy/initiatives/solar-future [Accessed 12 September 2019].

[8] Department of natural Resources, Mines and Energy (2019). A solar future: powering Queensland's renewable energy industries. Available from: https://www.dnrme.qld.gov.au/energy/initiatives/solar-future [Accessed 12 September 2019].

[9] Department of natural Resources, Mines and Energy (2019). Delivering effective energy policy outcomes. Available from: https://www.dnrme.qld.gov.au/energy/initiatives/powering-queensland [Accessed 12 September 2019].

[10] Business Queensland (2016). Solar 150 – Queensland's large-scale solar investment program. Available from: https://www.business.qld.gov.au/industries/mining-energy-water/energy/renewable/projects-queensland/solar-150 [Accessed 12 September 2019].

associated with this solar output.[11] They also recognised that to deliver improved market outcomes, flexible resources should be rewarded for their ability to shift demand to the low load periods and to follow the ramp more effectively and efficiently.

The Queensland Government has encouraged the adoption of new technology in the past through an incentive program whereby households and small businesses were able to apply for interest-free loans or grants to purchase a battery system. We expect the Queensland Government to continue to encourage adoption of new technology as the state progresses toward the Government's 2030 target of 50 per cent renewable energy generation.

Electric vehicles

An EV is defined as any vehicle that is fully or partially driven by an electric motor and can be plugged in to recharge. The two types of EVs are the battery electric vehicle (BEV) and the plug-in hybrid electric vehicle (PHEV).

The electrification of transportation is part of an over-arching structural change in Queensland's transport and energy systems. This change is primarily driven by the well understood impacts of climate change and, accordingly, the Queensland Government's commitment to meeting a target of 50 per cent renewable energy generation by 2030.[12]

As with solar PV, government initiatives are also driving the uptake of EVs. In recognition of the global support for EV technology, and the need to encourage local uptake, the Queensland Government launched The Future is Electric – Queensland's Electric Vehicle Strategy paper in 2017. The Strategy consisted of 16 initiatives aimed at:

- empowering consumers to make informed choices;
- enabling EV charging infrastructure;
- exploring cost-effective programs to support uptake of EVs; and
- envisaging what future actions may be required.

For example, one initiative in the Strategy is the Queensland Electric Super Highway – the world's longest EV superhighway within a single state. The network of fast EV charging stations initially spanned from Cairns down to the New South Wales border and will expand to other regions in possible future phases.[13] More recently, the Queensland Government announced Australia's first EV tourism driving network. The 500-kilometre Tropical North Queensland Electric Vehicle Drive will feature six electric vehicle charging stations at key tourist attractions across the Cairns region.[14]

As at 30 June 2018, there were 1,562 plug-in electric vehicles registered in Queensland, comprising of 798 BEVs and 764 PHEVs. EVs represent 0.04 per cent of the Queensland fleet.[15] A significant adoption rate of EV in Queensland over time has been predicted due to vehicle model availability, elimination of purchase premiums and falling battery storage costs.[16] It was also predicted that yearly

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[11] Australian Energy Market Operator (AEMO) (2018). AEMO observations: Operational and market challenges to reliability and security in the NEM. Australian Government, Canberra.

[12] Department of natural Resources, Mines and Energy (2019). Powering Queensland: an integrated energy strategy for the state. Available from: https://www.dnrme.qld.gov.au/energy/initiatives/powering-queensland [Accessed 12 September 2019].

[13] Queensland Government (2017) The Future is Electric: Queensland's Electric Vehicle Strategy 2017.

[14] https://energylive.aemo.com.au/Innovation-and-Tech/FNQ-EV-drive-tourism

[15] Queensland Department of Transport and Main Roads, *Submission to the Queensland Parliament Transport and Public Works Committee Inquiry: Transport Technology—the challenges and opportunities which technology will bring to the transport sector in coming years*

[16] Energeia (2017), Electric Vehicle Insights, prepared for the Australian Energy Market Operator's 2017 Electricity Forecast Insights.

new EV sales would increase from 0.1 per cent in 2017 to 16.8 per cent and 89.8 per cent in 2030 and 2050 respectively.

EVs can be charged using locally-produced, renewable energy, including rooftop solar, which has the potential to offset some of the costs to the energy markets, either by shifting demand (charging your vehicle earlier or later in the day) or as a source of supply and ancillary services from the batteries within EVs (so called vehicle to grid or V2G). It also provides the transport sector with the opportunity to significantly reduce its emissions through the uptake of EVs.

Queensland has the world's second highest levels of household Solar PV penetration at 24.12% (almost 1 in every 4 households) and is uniquely placed within the global market to take advantage of the numerous potential benefits of an integrated vehicle-battery-solar system, at both the small-scale residential and largescale community levels.[17] However, this will mean management of the electricity network will need to evolve and address this emerging technology and its impact on energy usage.

New aggregation market

The development of a viable and active aggregation market is seen as a natural evolution for the energy industry in Australia.

An aggregator market would leverage customer-side technology, such as solar PV and batteries, and trade this energy and capacity on the evolving national energy market on behalf of customers. An active and engaged aggregator market is seen by EQL as a way to support our customers to participate and gain benefit from national energy markets without the need to directly engage themselves. We also envisage benefits that may be achieved from an active aggregator market by being able to procure services in a locational-specific area, including leveraging aggregators to reduce peak demand on one specific constrained network area.

However, an active aggregation market needs to be managed effectively as aggregators that are leveraging customer technology on the national market may remove diversity from customer loads or generation across our networks. For example, if an aggregator has a substantial amount of residential energy storage under contract in a single location and they dispatch this capacity to meet a national market price. The net impact on the distribution system may be significant. Our tariffs therefore need to support our customers who wish to participate in national markets through aggregators but provide price signals to manage this locational non-diversified risk that may emerge.

The network tariff implications of these new technologies are discussed in the next section of this chapter.

3.2 Addressing future changes and challenges

EQL's Network Planning, Demand Management (DM) and Tariff strategies share a common goal: to transform our network into a multi-directional, multi-embedded, multi-technology network platform of the future. Our Planning, DM and Tariff strategies work together to respond to the current and emerging trends that are facing our network and are driving the need for tariff reform. These trends, which are further exacerbated by the increasing probability of extreme weather events and temperatures due to climate change, include:

[17] Queensland Government (2017) The Future is Electric: Queensland's Electric Vehicle Strategy 2017.

- Flattening demand and consumption growth at a system level, however we expect some localised areas of demand growth causing the need for network augmentation;
- The large latent air-conditioner load exacerbating the early evening peak and outages during extreme heat wave events;
- Take-up of electric vehicles which, if convenience charged, could exacerbate the early evening peak;
- Continued take up of solar PV causing localised and regionalised voltage management issues in the midday period when solar output is peaking;
- Future take-up of home batteries with solar PV effectively allowing solar generation to be used in any time period; and
- The development of a dynamic aggregation market that can leverage increasing technology capabilities.

EQL's DM and Planning teams work together to deliver prudent and efficient non-network and network solutions. For example, as opposed to traditional network solutions, the use of these non-network alternatives (also known as DM) provides increased optionality and ensures our investment choices are optimised for a wide range of possible futures. DM involves working closely with customers and industry partners to reduce demand and/or manage energy and leveraging customer led investment to improve and complement efficient investment in network.

Lower peak demand growth with some areas of localised peak demand growth

Non-tariff DM incentives are offered in Target Areas (areas with localised network constraints potentially due to customer growth) with the aim of reducing demand and negating or deferring the need for augmentation. These incentives are complementary to cost reflective tariffs but provide a 'sharper' locational incentive to encourage the adoption and use of technology to reduce network risk (in line with short run costs).

Greenfield developments are an example of localised areas of demand growth, and provide a good example of where Planning, DM and Tariffs to work together:

- Planning studies identify future network constraints due to greenfield residential or business developments;
- DM incentives encourage the adoption of 'behind the meter' technology to reduce network constraints in the short term and at the same time grow the market for demand response in the future;[18] and
- Cost reflective tariffs provide an ongoing price signal to which customer side technology can respond to.

Load control tariffs as a complement to DM initiatives

To address localised demand growth, it is proposed to introduce primary controlled load tariffs to SAC Small and offer primary and secondary controlled load tariffs to SAC Large customers. The rationale for this is to broaden customers' access to load control load tariffs and to increase demand reduction capability (when required) in areas that have predominantly non-residential loads (e.g. irrigation pumping). This is informed by recent trials with agricultural customers whereby peak demand was driven by irrigation loads.

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[18] 'Behind the meter' refers to energy products or services located on the customer's side of the electricity meter, such as solar, battery energy storage systems, electric vehicle charging products, energy management systems and software, and other emerging products and services for homes and businesses.

In terms of residential customers, we currently have around 544MW and 202MW of hot water and air conditioning load under control (i.e. appliance loads that are connected to controlled load tariffs) on each of the Energex and Ergon Energy networks respectively. The demand reductions available from load control tariffs for these customers are factored into the networks' demand forecasts for the 2020-25 regulatory control period, thereby reducing future network costs. This is a positive practical outcome of our tariff strategy complementing network investment decision-making and is the primary driver of our proposed broadening of load control tariffs available in the 2020-25 regulatory control period.

Large air-conditioner load exacerbating the early evening peak, and outages during extreme heat events

DM solutions are also a better alternative than network augmentation when responding to the peak demand from air conditioning during extreme heat events as they occur infrequently, are usually localised and occur both inside and outside of identified constrained areas. Under our DM program, currently the largest in Australia, we have two key initiatives:

- Targeted initiative – offered in select areas where demand reduction is required to address a network constraint identified by Planning, and
- Broad Based initiative – offered across Queensland and can be used to reduce demand across our entire network. This initiative currently includes controlled load tariffs and the non-tariff option such as the PeakSmart air conditioning incentive program.

To address peak demand caused by air conditioning load during heat wave events, we currently have over 100,000 air-conditioners enrolled across Queensland in our PeakSmart air conditioning incentives program. Through our Load Control System (LCS) we can enact an event-based switching program that reduces air-conditioning demand during extreme heat wave or other peak demand events either locally or network wide. This capability is effective for managing the diverse range of climatic triggers in Queensland, such as a heat wave in the Southeast corner and mild conditions in the Far North. It is also useful for responding to system-wide events at the discretion of AEMO or Powerlink in order to manage the overall system stability in the event of a system disturbance, such as what occurred in the 2017 South Australian blackouts.

This event-based switching program also includes altering the daily switching program to ensure load under control is off during the event, and orchestrates the staggered return of load under control, so a secondary peak is avoided.

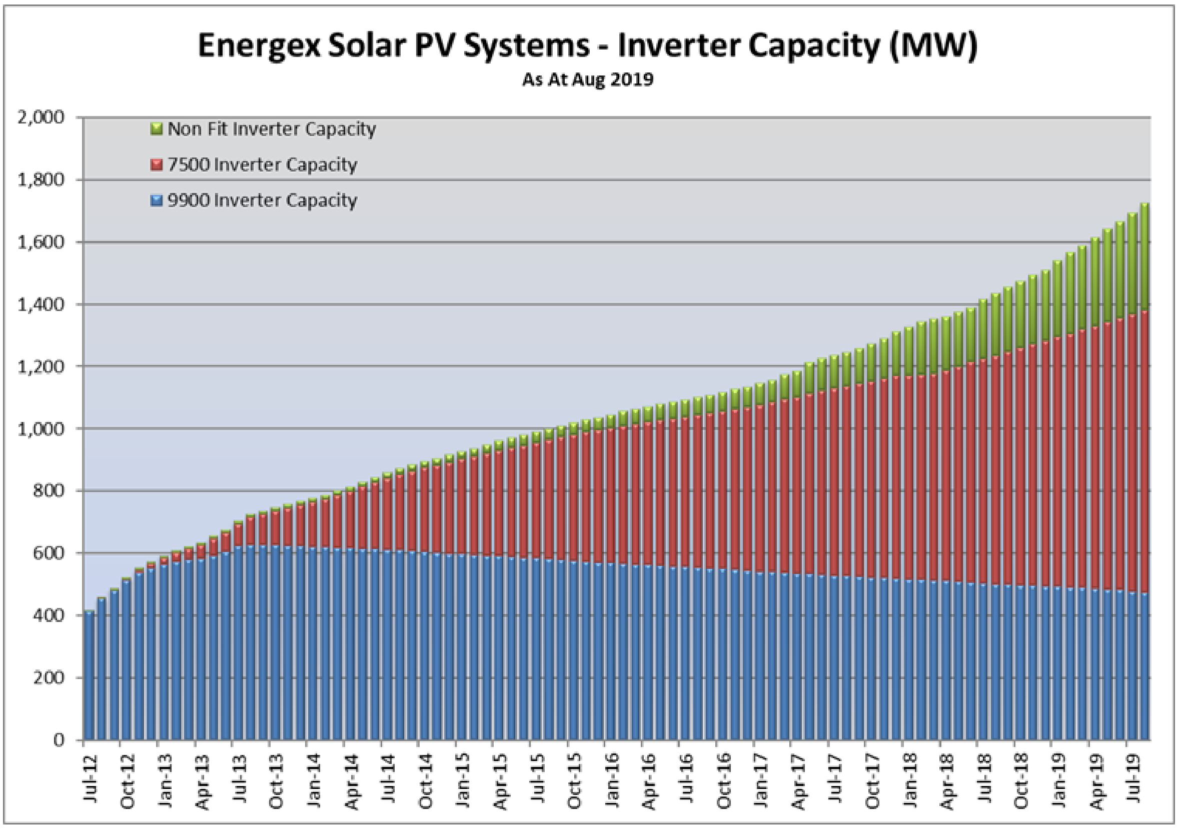
Forecast take-up of electric vehicles

An emerging trend with the potential to impact peak demand is electric vehicles (EVs), which are becoming more common in Australia and if convenience charged at home, could exacerbate the 4.00pm to 9.00pm peak. The impact of EV charging needs on peak demand will need to be mitigated. Instead of network augmentation, ToU energy and demand tariffs provide a solution to manage peak demand impacts by discouraging charging during the peak period and encouraging charging during off peak or shoulder periods. Another alternative is to encourage EVs to connect to a controlled load tariff, which provides a 'set and forget' option for customers and allows customers to avoid the negative impact of ToU energy and demand tariffs, without any loss of amenity, while increasing demand flexibility to respond to network of system events.

Continued take up of solar PV

ToU energy and demand tariffs are also designed to address solar PV by encouraging more self-consumption of solar. Over the last couple of years, rooftop PV installation have been accelerating, particularly on the Energex network. The installation rate within the Energex network alone is now close to 300MW per year and inverter capacity growth is currently around 20 per cent per year, as shown in the figure below.

Figure 5 - Solar PV capacity on the Energex network



EQL's initial network forecasting has indicated that the high rates of PV uptake are likely to continue and will be required to meet the Queensland Government's 50 percent renewable energy target. Without coordination, the continued take up of solar PV would require significant investment in voltage management.

There is significant potential to shift load under control into the growing 'troughs' to help manage network voltage. Under the solar sponge tariff-based initiative, we are implementing alternative switching programs whereby electric storage hot water systems on controlled load tariffs are heated during the middle of the day rather than overnight, where appropriate.

Load under control (i.e. appliance loads that are connected to controlled load tariffs) can be managed via the Load Control System (LCS) in several ways, including everyday time schedule (e.g. controlled load tariffs), event-based time schedule (e.g. PeakSmart air-conditioners during heat wave events) and dynamic threshold. In this way, load under control can be optimised to suit the network constraint being addressed, and provides demand response capability in the short term, while the demand response market and associated systems mature.

Analysis shows a slow decline of around 1-2% each year in take up of residential load control tariffs. The predominant reason for residential customers switching away from controlled load tariffs is the addition of a solar PV system and connection of hot water system to their primary tariff, with a timer, so that they can use their solar PV to heat their hot water system in the middle of the day. The implementation ToU energy and demand tariffs alone are unlikely to arrest this trend. This is another reason why we are looking to expand controlled load tariffs to additional customer segments, as outlined above. We expect that customers without solar; customers with solar on the premium feed-in-tariff and those looking to minimise their exposure to peak period pricing will remain assigned to controlled load tariffs. In this way-controlled load tariffs complement primary tariffs and provide additional choice for customers to manage their energy costs.

In contrast, we expect that customers without solar PV; customers with solar on the premium feed-in-tariff and those customers looking to minimise their exposure to peak period pricing, will remain on load control tariffs. In this way load control tariffs complement our primary tariffs and provide additional choice for customers to manage their energy costs.

Future take-up of home batteries with solar PV

The proposed ToU energy and demand tariffs will include peak pricing in the early (4.00pm – 9.00pm) evening to encourage battery use and low daytime pricing to encourage self-use of solar generation. These cost reflective tariffs may also encourage the uptake of home batteries and Home Energy Management Systems (HEMS) to our network, and we anticipate demand response services from DER will become increasingly available to the broader energy services market.[19]

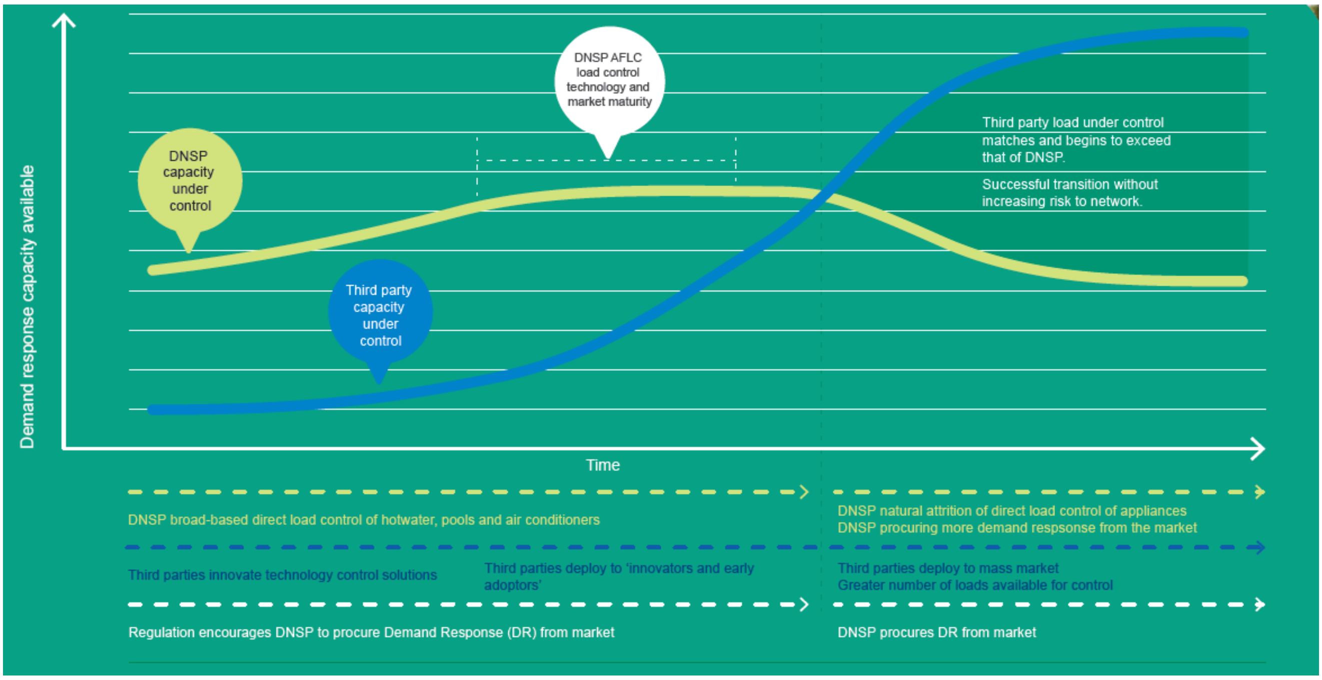
In recent trials conducted by Energex and Ergon Energy, batteries with and without HEMS were found to be effective at reducing peak demand of residential customers, but reliability of battery and HEMS were found to be a concern. The reliability issues were predominantly associated with battery inverters and HEMS communication hardware and software.

In these same trials, batteries with and without HEMS were not effective in reducing peak solar PV generation. Solar PV is typically paired with a battery that can store 20%-50% of the solar generation and as such, the battery is full by 11 am, meaning that peak solar export still occurred around midday with significant export continuing into the afternoon. The proposed tariffs alone may not provide enough incentive to minimise peak export and may need to be paired with battery charging algorithms and/or customer behaviours that reduce peak solar export. The value of batteries is maximised when the market and tariff design incentivise behaviour that supports very local behaviour.

As previously noted, we expect that customers with solar PV will transition away from load control tariffs. In light of this, we expect to procure more demand response services from the market, which will make up a growing proportion of our demand response portfolio. This is demonstrated in the figure below from our 2019-20 Demand Management Plan.

[19] It should be noted that in the future, DER could also be providing services to other markets (e.g. Frequency Control Ancillary Services (FCAS), wholesale energy market) and that at times, demand and/or ToU price signals may be unable to compete with other market signals. This issue has been flagged with ENA during consultation on the design of the future Distribution System Operator.

Figure 6 – Demand Response Procurement



4 TARIFF AND CORPORATE STRATEGY ALIGNMENT

Our commercial sustainability is dependent on successfully navigating the challenges posed by emerging technologies, falling electricity consumption and fundamental changes in the way customers use the distribution network. Network tariffs are a critical component of our response to these challenges by providing customers with more cost reflective signals. This will improve fairness by reducing cross-subsidies and costs by putting downward pressure on network investment over the longer term through rewarding customer responses to these signals.

We recognise the pivotal role network tariff reform plays within the wider business. For this reason, our network tariff strategy has been carefully developed with a view to align with its corporate strategy, customer strategy and DM strategy in order to achieve more efficient outcomes and meet customer expectations. Such a coordinated approach will ensure we will deliver our commitment to provide services our customers need.

4.1 Corporate strategy

As part of the Energy Queensland Group, we have developed a strategic framework that lays the foundation for us to be a more agile, innovative and responsive participant in the ever changing energy market environment.

Our proposed network tariff strategy supports Energy Queensland’s vision to Energise Queensland Communities by enabling its purpose in safely delivering secure, affordable and sustainable energy solutions with our communities and customers.

Energy Queensland’s over-arching strategic framework is depicted in Figure 7 below.

Figure 7 - Energy Queensland’s Strategic Framework

4.2 Interaction between tariff strategy and customer strategy

Our tariff strategy in its simplest form is underpinned by a move from volume-based to cost reflective network tariffs. This can occur upon the acceptance of our strategy by our customers and stakeholders and will be enabled by optimising the technology and regulatory contexts. We know this will be a journey that requires co-operation between us and the whole industry, and that the journey must begin now to ensure everyone benefits in the medium to long-term.

Network tariff reform sits in the broader context of our Customer Strategy in delivering success for both our customers and our business. Our goal is to deliver valued experiences based on a foundation of knowledge and understanding the diversity of needs across all of our customers.

Our Customer Principles and their relationship to our Tariff Strategy are outlined in Table 1 below.

Table 1 - Customer Principles

Customer Principle	Relationship to Tariff Strategy
Know our Customers	• We have consulted widely with customers on the proposed suite of tariffs in our 2020-25 TSS, and we will continue to seek customer feedback via tariff trials we will conduct in the lead-up to and post 2020.
Deliver Value	• Our goal is to provide customers with a selection of tariffs they can utilise to best optimise their relationship with electricity. As the industry, tariffs and customer behaviours develop, our strategy is to further develop our tariff suite to create further opportunities for customers to participate in the market as we progress towards cost-reflective network pricing. • We want to ensure network tariffs promote efficient use of the network that will deliver sustainable outcomes for customers.
Make it Easy	• Our goal is to develop tariffs that are easily understood by customers and retailers and can be responded to in maximising customer value.

4.3 Interaction between tariff strategy, DM and network planning

Our network planning, DM and tariff strategies share a common goal: to transform our network into a multi-directional, multi-embedded, multi-technology network platform of the future. In managing our augmentation expenditure (Augex), we deliver prudent and efficient non-network and market driven solutions. As opposed to traditional network solutions, the use of these alternatives provides increased optionality and ensures our investment choices are optimised for a wide range of possible futures.

Important parts of this work include:

- Forecasting future total and peak load both on a system-wide basis and on geographical/network topography basis, and
- Identifying and implementing non-network alternatives to avoid the need for additional network infrastructure.

Forecast and actual peak load is currently a key driver of Augex. Whilst in the future we anticipate Augex will not be heavily driven by seasonal customer demand, if we are to continue to reduce network tariffs in real terms, we must look at a variety of avenues to manage load.

Our two primary vehicles in achieving this objective are to continue to implement DM strategies and to introduce cost reflective network tariffs.

DM is an integral part of our approach to forecasting, planning and developing tariff, intelligent grid and customer strategies. DM involves working closely with end use customers and industry partners to selectively reduce demand with the intention of maintaining system reliability in the short term and over the long term, deferring the need to build more ‘poles and wires’. We plan to support the introduction of network tariff reform with dynamic incentives that combine load control and locational demand management programs.

Our DM programs complement both a demand tariff scenario and a capacity tariff scenario providing a mitigant where network constraints or congestion would result in network investment. The DM programs and our network tariff strategy will work together in the following ways to help optimise network investment and bring down network costs for customers.

- We have around 202MW of load under ‘control’ via traditional load control tariffs. The demand reductions available from load control tariffs are factored into the demand forecast, thereby reducing network costs
- We also have around 2MW of load under control in relation to the PeakSmart air conditioning incentives program. This ‘control’ is exercised when required to manage peak demand but it is not always available where and in the quantity needed
- In addition, with customers increasingly connecting DER such as solar photo-voltaic (PV) systems, batteries and Home Energy Management Systems (HEMS) to our network, we anticipate demand response services from DER will become increasingly available. As customers transition away from load control tariffs, demand response procured from the market (for example, via customer incentives) will make up a growing proportion of our demand response portfolio, and
- We believe that there is significant potential for shifting ‘troughs’ in demand. This would provide improvements in network utilisation and reduction in power quality issues with minimal customer impact. Traditionally the audio frequency load control (AFLC) program has been used to reduce system peak demand. With the “Solar sponge” initiative, we are now trialling an alternative switching program whereby electric storage for hot water systems on control load tariffs are used as a ‘solar sponge’ to integrate renewables into the network.

5 NETWORK TARIFFS

5.1 Recovering costs

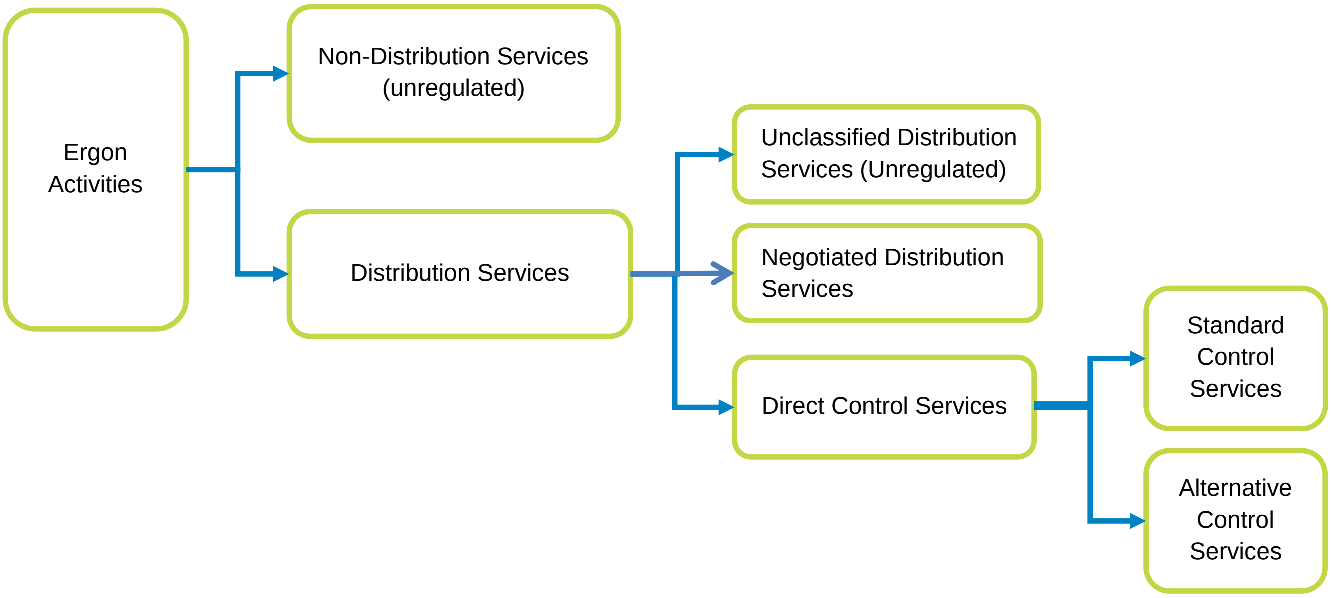
The AER determines how our distribution services are classified and in turn the nature of the economic regulation. This is important as it determines how tariffs will be set and how charges are recovered from customers.

Services incorporated within the customer's electricity bill relate to services that are central to electricity supply using our poles and wires. These services, classified as Standard Control Services (SCS) in accordance with the F&A, relate to the access and supply of electricity using our poles and wires (distribution system) to customers. Specifically, they include network services (e.g. construction, maintenance and repair of the distribution system) and some connection services (e.g. small customer connections).

Customer specific or customer requested services, classified as Alternative Control Services (ACS), are charged separately. ACS are comprised of ancillary services, some connection services, type 6 metering services and public lighting services in accordance with the F&A.

Our TSS relates to the tariffs for those distribution services classified by the AER as direct control services (SCS or ACS) as shown in the Figure 8 below.

Figure 8 - Classification of Ergon Energy's distribution services



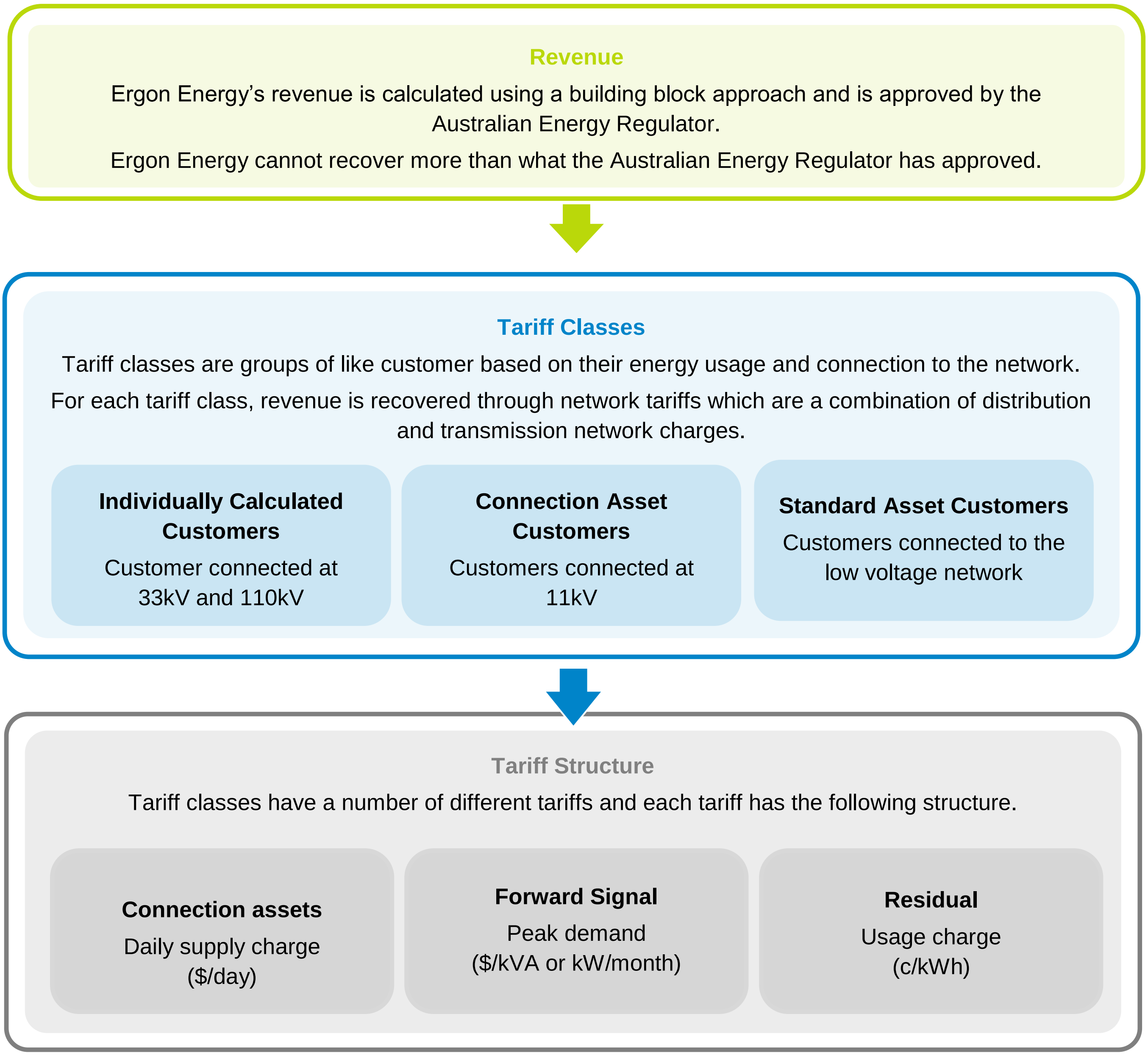
There are three primary sources of revenue that we recover through network use of system (NUOS) charges:

- Distribution Use of System (DUOS) revenue
- Jurisdictional Scheme amounts (if applicable), and
- Designated Pricing Proposal Charge (DPPC) (transmission network) revenue.

We recover our allowed revenue through network tariffs in a way that is consistent with the pricing principles set out under the NER. The tariff structures outlined in the TSS do not affect how much revenue we can earn. Instead, they determine how revenue is recovered from particular customer groups.

We charge NUOS charges to electricity retailers. Customers may not see our network charges itemised on their retail electricity bill, as the retailer incorporates our network charges into their retail prices and charges, along with other costs of producing and supplying electricity.[20] In 2018-19, network costs comprised approximately 38 per cent of the retail bill for a small customer.[21] Our allocation of allowed revenue is illustrated in Figure 9 below.

Figure 9 - Ergon Energy allocation of its allowed revenue to its tariff classes



[20] There is also no requirement under the NER for a retailer's tariff structure to follow the same structure as the network tariff.

[21] Queensland Competition Authority's Regulated Retail Electricity Prices for 2018-19, May 2018.

Further to these NUOS charges, additional charges may apply where a customer requests the provision of specific services (such as special meter reads or disconnections). The level of the charges we can apply for these services, classified as ACS, are regulated by the AER.

5.2 Our network tariff components

Our network tariffs are underpinned by key concepts, including tariff classes, tariff structures, and charging parameters and levels.

The sections below provide further explanation of these concepts as they apply to us.

5.2.1 Tariffs and tariff classes

We have over 750,000 residential and business customers, with a range of different characteristics. We group customers that have similar characteristics together so that similar customers are assigned to the same tariffs that are available under their tariff class.

At the broadest level, we differentiate between tariff classes based on the voltage level at which a customer is connected to its network and the amount of electricity that they consume annually.

The key voltage levels used for tariff setting purposes are the sub-transmission, high voltage (HV) and low voltage (LV) levels of the network. The majority of our customers – residential and small business – are connected at the LV level of the network, with a relatively small number of large business customers connected at the sub-transmission or HV levels of the network.

5.3 Network tariff charging parameters

A network tariff may be made up of several separate charging parameters. The charging parameters that may be used when constructing network tariffs include the following:

- Daily supply charge (also known as fixed charge)
- Flat charge (also known as energy or volumetric charge)
- Time of Use (ToU) energy charge
- Demand charge
- Excess demand charge
- Capacity charge (ICC and CAC)

Depending on whether a network tariff is designed for large or small customers, these different charging parameters can also serve different purposes as explained further below.

5.3.1 Daily supply charge

The daily supply charge is a dollar ($) per day charge applied regardless of usage to each energised connection point.

There are a number of 'fixed' costs that we must recover for assets that have already been built and must be maintained for a long period of time. For small customers, daily supply charges are designed to recover costs associated with a customer's connection to the network. Portions of the residual shared network costs are also collected through daily supply charges. For large customers, daily supply charges reflect the costs associated with the connection and management of the customer.

5.3.2 Energy usage charge

Inclining block charge

This charge is calculated in cents or dollars per kilowatt hour ($/kWh) with different increasing rates applying to blocks of electricity consumed during the billing period. This charge recovers all or some of the costs that are not recovered from the daily/monthly supply charge.

Time of Use (ToU) energy charge

This charge is calculated in cents or dollars per kilowatt hour ($/kWh), depending on the tariff, with different rates applying to the electricity consumed at a connection point at different times of the day. For small customers, ToU usage charges can recover costs that have not been recovered from a demand charge or daily supply charge.

These charges are designed to incentivise the reduction of demand on the network during peak times by encouraging customers to switch non-essential electricity usage to off-peak and/or shoulder times.

5.3.3 Demand charge

Demand charges are levied on the basis that network users who place greater pressure on the network during peak should incur higher charges.

Typically this is a monthly charge calculated as a $/kilowatt (kW) or $/kilovolt ampere (kVA) rate for the maximum (or peak) demand recorded.

Generally demand is metered at a customer's connection point where the maximum demand placed on the distribution network at any time, or at a specific time, or within a specific time is recorded (traditionally in 30 minute intervals).

For larger customers (CAC and ICC) demand charging can be based on Authorised Demand (AD) which is determined either through contractual negotiation with the customer or determined as part of the annual network tariff setting process using historical data.

Demand charges deliver stronger network price signal than a usage charge alone as it reflects the incremental cost to support future capacity requirements.

5.3.4 Excess demand charge (SAC Large and CAC)

Represented as a rate ($) per excess kVA. The excess charge is measured as the single highest maximum demand outside the peak charging window minus the maximum demand during the peak period in the billing period. It only applies where the maximum demand outside of the period is higher than the maximum demand in the peak period.

5.3.5 Capacity charge (ICC and CAC)

This is a monthly charge calculated as a dollar per kilovolt ampere ($/kVA) rate for the amount of network capacity which is set aside for an individual customer to use at any time.

Capacity charges traditionally account for augmentation costs at the customer connection level and all associated upstream augmentation costs already incurred to provide sufficient network capacity to accommodate peak demand.

5.4 Legacy Considerations

Energex notes that in addition to the above tariff structures, the possibility exists that there could be a small number of legacy systems arrangements in place which pre-date the TSS requirements in the

NER. In the event Energex identifies the existence of any such arrangements, we commit to working with the AER and our Stakeholders to review as appropriate.

6 RATIONALE FOR THE SCS TARIFF CLASSES, TARIFF IMPLEMENTATION AND TARIFF STRUCTURES

This chapter explains the reasons for the proposed tariff classes, tariff implementation and tariff structures for SCS over the 2020-25 regulatory control period.

In broad terms, we are proposing a range of new cost reflective tariffs for the SAC tariff class, reflecting the increasing penetration of digital meters (Types 1-4 meters) for residential and small business customers. We are also proposing to introduce new primary and secondary load control tariffs for business customers in the SAC tariff class to complement our existing load control tariff suite, reflecting their importance to future network management. Tariffs for the CAC and ICC tariff classes are already cost reflective. However, several important tariff structure refinements and consolidation of existing tariffs are proposed.

6.1 Tariff classes

Under chapter 10 of the NER, tariff classes are defined as 'a class of customers for one or more direct control services who are subject to a particular tariff or particular tariffs'. All customers who take supply from us for direct control services are a member of at least one tariff class.[22]

In accordance with clause 6.18.4 of the NER, our tariff classes group retail customers on the basis of their energy use and connection to the network. Further, in accordance with clause 6.18.3(d) of the NER, our tariff classes group retail customers together on an economically efficient basis and to avoid unnecessary transaction costs.

In the 2017-20 TSS, the AER approved the following tariff classes:

Table 2 – AER approved tariff classes in 2017-20 TSS

Tariff Class	Customer connections	East	West	Mount Isa
ICC	ST, HV, LV		✓ (a)	
CAC	ST, HV, LV	✓	✓	✓ (a)
EG	EG ST, HV	✓	✓	✓ (a)
SAC Large	HV, LV	✓	✓	✓
SAC Small	LV	✓	✓	✓
SAC unmetered	Unmetered	✓	✓	✓
(a) There are presently no customers in these tariff classes in Mount Isa Region.				

Where ST represents the 110kV, 132kV, 66kV and 33kV voltage levels, and HV represents the 11kV and 22kV voltage levels.

Given the complexity of the current tariff class suite due to the inclusion of regional distinctions it is proposed to rationalise tariff class arrangements within our network. The proposed set of tariff classes shown below demonstrates a greater level of rationalisation and alignment of tariff classes for the 2020-25 regulatory control period.

[22] Standard control services and alternative control services comprise direct control services.

Table 3 - Proposed Tariff Classes for 2020-25

Tariff class	Ergon Energy		
	East	West	Mount Isa
ICC	✓		
CAC	✓	✓	✓
SAC	✓	✓	✓

Where:

- SAC are customers typically connected at the LV network
- CAC have network coupling at ST or HV (66kV, 33kV, 22kV, 11kV) for East, West and Mount Isa, and
- ICC are customers coupled to the network at 110kV 66kV 33kV 22kV.

From 1 July 2020, we are proposing to remove the Embedded Generator (EG) tariff class. We are of the view that such a change would have the following advantages:

- The proposed tariff class structure is designed to align with the voltage level of a customer's connection to the network and will result in a simpler tariff class assignment process
- It will more closely align our tariff class structure with that of Energex, resulting in a more consistent tariff class assignment process across Queensland
- It will reduce unnecessary transaction costs as a result of fewer tariff classes to manage, and
- It ensures all tariff classes will align with the LRMC calculations undertaken at each voltage level of the network.

EGs coupled at 33kV and above will be allocated to the ICC tariff class and receive site specific pricing. EGs connected at 11kV will be allocated to the CAC tariff class and will continue to access their existing tariff.

It is noted that in 2015 the AER accepted Energex's proposal to consolidate its tariff classes as part of the 2015-20 regulatory proposal.

6.2 Implementation of tariffs

Under the proposed arrangements, existing customers on legacy tariffs will be minimally impacted in 2020. Depending on metering capability at their premises, customers with basic meters will either remain assigned to their legacy tariff and experience real decreases in their network charges, or for those with digital metering be assigned to a cost reflective tariff option which has been modelled on the basis of at least 99 per cent of customers seeing a reduction in their 2020-21 network charges.

It is also proposed that customers that have been assigned to a retail transitional tariff post 1 July 2017 can apply to opt in to grandfathered network tariffs from 1 July 2021.

Our network tariff implementation strategy for each of the ICC, CAC and SAC tariff classes for the 2020-25 regulatory control period is summarised below.

6.2.1 ICC tariff implementation strategy

The tariffs in the ICC tariff class are individually calculated based on the specific connection arrangements and network use of each customer and are cost reflective. No changes are proposed to the structure of these tariffs apart from the excess kVAr charge being discontinued.

However, based on our customer engagement, and in the interest of keeping as many customers connected to the network as possible to reduce the potential for adverse price impacts for all customers, the 2020-25 ICC tariff class definition will include scope for a clearly defined set of CAC customers to potentially be classified as ICC customers and access a 'non-standard' ICC network tariff solution.

In this regard, we propose to re-define the ICC tariff class eligibility criteria to enable CACs to be reclassified as ICCs on the grounds of customer bill impact combined with the existence of atypical network connection and usage arrangements[23] make it reasonable for such reclassification to occur.

During consultation it became evident that a group of agricultural, foundries and manufacturing CAC customers who are currently accessing transitional or obsolete retail tariffs in regional Queensland would be experiencing adverse electricity bill impacts once their retail transitional tariffs have been revoked. These customers have participated actively in both EQL and AER 2020-25 TSS consultation. The Customer Challenge Panel presentation at the AER workshop in Brisbane on October 17th 2019 noted the unusual circumstances and customer impacts facing this group of customers post 30 June 2021 when these particular retail tariffs will expire. The CCP pointed out the significant economic contribution that this group of customers make and the flow on effect in regional economies. In discussion it was also noted the revenue impact associated should these customers be lost to the distribution network ie the revenue shortfall from any resultant stranded assets would need to be recovered from other customers, thereby making the network less affordable for the remaining customer base and making network alternatives for these customers increasingly attractive.

Holistically it became evident during the consultation that based on this level of customer bill impact and/or the atypical nature of network usage/connection and configuration that a case could be made to review the ICC tariff classification to potentially allow classification of a restricted number of CAC customers in the ICC tariff class.

For the sake of greater transparency and consistency, we have developed an ICC tariff class reclassification policy which has been included at Appendix A of our Revised TSS.

We set out below how such an approach will benefit not only our CAC customers on a transitional retail tariff but also all customers, and how it aligns with pricing principles set out in the NER.

<u>Non-standard ICC network tariff solution – Alignment with economic principles</u>

The distribution pricing principles and network pricing objective establish an economic efficiency basis to the setting of network tariffs.

A key element of this economic efficiency objective is the requirement that tariff class revenues must fall between the stand alone cost of serving those customers and the avoidable cost of not serving those customers. This requirement establishes a proxy for network prices for individual customers that fall between an avoidable (or incremental) cost floor and stand alone cost ceiling being economically efficient.

In general, any network price that is lower than avoidable or incremental costs will be rejected on economic efficiency grounds. The reason for this is that any customer paying less than the incremental or avoidable cost it imposes on the infrastructure is essentially being subsidised by the service provider (in the event of less than full cost recovery) or by other users (in the event of full cost

[23] Including annual energy demand, diversity factor, power factor or load factor that are substantially different to average.

recovery). In the latter instance, other users would be better off in terms of a lower price if that customer was not served.

In contrast, any price set higher than stand-alone costs will be rejected on economic efficiency grounds because such a price implies a user would be better off by-passing the infrastructure, including potentially building its own infrastructure.

In principle, the level at which prices are set between incremental and stand-alone cost limits can be a matter for negotiation between the network service provider and customers, provided the negotiated price falls within the lower bound and ceiling range and generates revenues that recover the efficient costs of the service. In this regard, the negotiated price should, at a minimum, recover each customer's share of costs related to its consumption of the network service, which is the incremental cost-based lower bound.

In terms of economically efficient pricing, the distribution pricing principles further require each network tariff must be based on LRMC. Setting prices equal to LRMC signals the future costs of network capacity expansion and so promotes efficient use of and investment in network infrastructure. However, the forward-looking nature of LRMC means it will usually generate insufficient revenue to recover the total cost of existing assets. Hence, there is a need to recover the remaining revenue requirements (residual cost recovery) via additional charges in the least distortionary manner possible having regard to customers' energy consumption.

Having regard to these economic efficiency aspects of the distribution pricing principles, we propose non-standard ICC network tariff solutions for CAC customers that will be based on:

- A full LRMC price signal incorporated in the demand charging component of the tariff so that the signal.
- A full pass-through of transmission network use of system (TUOS) and any jurisdictional scheme costs.
- Transitioning of residual cost recovery over a period of up to 10 years (effected through setting the levels of the fixed and volume charging components of the non-standard ICC tariff).
- Residual DUOS cost recovery set at a level that ensures all other network customers remain better off from the re-assigned CAC customer staying connected to the network compared to the situation if that customer disconnected.
- This approach to residual cost recovery will ensure that the customers assigned to the non-standard ICC tariff will pay a network price that is above the avoidable (or incremental) cost of supplying that customer.

EQL believes that this approach to setting the non-standard ICC tariff will result in an economically efficient price that does not reflect any cross subsidy from other network customers.

A summary of compliance of this non-standard ICC tariff with the distribution pricing principles is presented in the table below.

Distribution pricing principle	Description	Compliance description
Cl. 6.18.5(e).	For each tariff class, expected revenue to be recovered from customers must be between the stand alone cost of serving those customers and the avoidable cost of not serving those customers.	Non-standard ICC tariff re-assignments will not result in CAC and ICC Tariff class revenues breaching the stand alone cost and avoidable cost boundaries.

Cl. 6.18.5(f).	Each tariff must be based on the long run marginal cost of serving those customers, with the method of calculation and its application determined with regard to the costs and benefits of that method, the costs of meeting demand from those customers at peak network utilisation times, and customer location.	The non-standard ICC network tariff solution will incorporate a full LRMC price signal.
Cl. 6.18.5(g).	Expected revenue from each tariff must reflect the distributor's efficient costs, permit the distributor to recover revenue consistent with the applicable distribution determination, and minimise distortions to efficient price signals	Transitional residual cost recovery will be reflected in the fixed and volume charging components of the non-standard ICC tariff to minimise distortions to affected customers' energy consumption.
Cl. 6.18.5(h).	Distributors must consider the impact on customers of tariff changes and may depart from efficient tariffs, if reasonably necessary having regard to: • the desirability for efficient tariffs and the need for a reasonable transition period (that may extend over one or more regulatory periods). • the extent of customer choice of tariffs. • the extent to which customers can mitigate tariff impacts by their consumption	We propose that the proposed residual cost departure from the standard fully cost reflective ICC tariff will be applied on a transitional basis for 10 years in order to manage potentially adverse customer impacts for the re-assigned CAC customers. The non-standard ICC network tariff solution will be available only to existing customers on transitional tariffs and on an opt-in basis. We will not force re-assignments of CAC customers to the non-standard ICC tariff, reflecting its transitional nature.
Cl. 6.18.5(i).	Tariff structures must be reasonably capable of being understood by retail customers assigned to that tariff	The non-standard ICC tariff structure will be reasonably capable of being understood by affected CAC customers given its charging components are comparable to the CAC tariff class tariffs.
Cl. 6.18.5(j)	Tariffs must otherwise comply with the Rules and all applicable regulatory requirements.	The non-standard ICC tariff complies with the Rules and all applicable regulatory requirements.

6.2.2 CAC tariff implementation strategy

The current suite of anytime demand tariffs in the CAC tariff class that are differentiated by the voltage line or bus level at which the customer is connected, are proposed to be retained for all existing and new CAC customers.

However the existing seasonal ToU demand tariffs are proposed to be retired on 1 July 2020.

As discussed in the preceding section on ICC tariff implementation, as part of the 2020-21 CAC rate setting process it is proposed to undertake an analysis of individual CAC customer outliers with a view to considering their re-classification as an ICC customer in accordance with the approved re-assignment criteria.

Table 4 - CAC tariff implementation strategy

Tariff	2020-25 Status	Availability
CAC 66kV	Default	New and existing customers
CAC 33kV	Default	New and existing customers
CAC 22/11kV Bus	Default	New and existing customers
CAC 22/11kV Line	Default	New and existing customers
Seasonal ToU Demand HV	Retired	N/A
Seasonal ToU Demand 22/11kV Bus	Retired	N/A
Seasonal ToU Demand 22/11kV Line	Retired	N/A
Note: This applies across the East, West and Mount Isa pricing zones.		

6.2.3 SAC Large tariff implementation strategy

We propose that the current suite of anytime demand tariffs be retained for all existing and new customers, with the existing seasonal ToU demand tariffs to be grandfathered on 1 July 2020 as these will be superseded by the proposed ToU demand tariff. In addition, we are proposing to introduce primary and secondary load control tariffs for SAC Large customers.

Table 5 - SAC Large tariff implementation strategy

SAC User Group	Tariff	2020-25 Status	Availability
SAC Large	Demand Large	Opt in	New and existing customers
	Demand Medium	Opt in	New and existing customers
	Demand Small	Opt in	New and existing customers
	Time of Use Demand	Default	New and existing customers
	Seasonal Time of Use Demand	Grandfather	Existing customers
	Large Business Primary Load Control	Opt in	New and Existing Customers
	Large Business Secondary Load Control	Opt in	New and Existing Customers
Note: This schedule applies across our East, West and Mount Isa pricing zones.			

6.2.4 SAC Small Residential and SAC small business tariff implementation strategy

6.2.4.1 Residential customers

We are proposing to introduce the following tariff options for SAC Small Residential customers with digital meters in 2020-25:

- Transitional Demand Tariff;
- Demand Tariff; and
- ToU Energy Tariff.

The Transitional Demand Tariff is proposed to be the default tariff for new customers who will have the necessary digital meters. The difference between the Transitional Demand and Demand Tariff is that the level of the demand charge in the latter tariff will be set higher (in $/kW terms) to provide a stronger LRMC-linked price signal regarding the cost of future network augmentation. The lower level of the demand charge in the Transitional Demand tariff is intended to limit the network cost impact on customers reassigned to cost reflective tariffs and assist customers transition to and gain greater comfort regarding demand tariffs.

The ToU Energy Tariff is proposed to be offered on an opt-in basis and reflects stakeholder concerns that some residential customers may have difficulty understanding demand tariffs in contrast to a ToU Energy Tariff.

The default tariff for existing customers with basic accumulation meters will continue to be the existing IBT Residential Tariff. However, any customers on this tariff who have digital meters will be re-assigned to the Transitional Demand Tariff on 1 July 2021 consistent with the overarching network tariff reform objective of transitioning all customers to cost reflective tariff structures. From 1 July 2020, residential customers with digital meters will be able to opt in to the Transitional Demand Tariff, Demand Tariff or ToU Energy Tariff at any time during the 12 month grace period.

Additionally, two transitional network ToU energy and a transitional network dual rate demand tariff will be available to SAC Small customers who have been on a matching transitional retail tariff since 1 July 2017.

Table 6 - SAC Small Residential tariff implementation strategy

SAC User Group	Tariff	2020-25 Status	Availability
SAC Small Residential	Residential Transitional Demand	Default from 1 July 2020	New and existing customers with digital metering. Existing customers may remain on their legacy tariff until 30 June 2021
	Residential Demand	Opt in	New and existing customers with digital metering
	Residential ToU Energy	Opt in	Existing and new customers with digital metering
	IBT Residential	Default	Existing customers with basic metering
	Seasonal ToU Energy	Retired	Customers reassigned to either the default IBT or default Transitional Demand Tariff depending on the customer’s metering
	Seasonal ToU Demand	Retired	Customers re-assigned to Residential Transitional Demand

Note:
This schedule applies across our East, West and Mount Isa pricing zones.

6.2.4.2 Small Business customers

We are also introducing a similar set of new tariff options for SAC Small Business customers with Type 1-4 digital meters in the 2020-25 regulatory control period. These are as follows:

- Transitional Demand Tariff
- Demand Tariff and
- Small Business Time of Use Tariff.

For existing customers with basic accumulation meters and consuming less than 20MWh per annum, the existing IBT Small Business Tariff will remain the default tariff.

It is proposed that customers with basic accumulation meters consuming more than 20 MWh per annum will be re-assigned to a new Wide Inclining Fixed Tariff (WIFT) on 1 July 2020. The WIFT will not be available to customers with Types 1-4 digital meters.

The tariff's structure is as follows:

- Inclining fixed charge in $ per day based on 20MWh per year blocks: 0-20, 20-40, 40-60, 60-80, 80-100 MWh per year; plus
- Flat volume charge in $ per kWh.

The inclining fixed charge structure has been developed to:

(1) recognise business customers' connection sizes (with consumption being a proxy); and
(2) minimise customer impact for business customers who are near the SAC Large 100MWh/year threshold and could end up being assigned to a SAC Large Demand tariff.

If a small business customer's consumption exceeds 20MWh per year, it will be re-assigned from the IBT to the WIFT.

The first consumption block of the WIFT has been priced to be similar to the IBT down to a consumption level of 15MWh to minimise any potential adverse customer price impacts due to the tariff re-assignment.

Table 7 - SAC Small Business tariff implementation strategy

SAC User Group	Tariff	2020-25 Status	Availability
SAC Small Business	Small Business Transitional Demand	Default from 1 July 2020	New and existing customers with digital metering. Existing customers may remain on their legacy tariff until 30 June 2021
	Small Business Demand	Opt in	New and existing Customers with digital metering
	Small Business IBT	Default	Existing customers with basic metering
	Small Business ToU Energy	Opt in	New and existing Customers with digital metering
	Seasonal ToU Energy	Retired	Customers reassigned to Small Business Transitional Demand or IBT
	Seasonal ToU Demand	Retired	Customers reassigned to Small Business Transitional Demand
	Small Business Primary Load Control	Opt in	New and Existing Customers

SAC User Group	Tariff	2020-25 Status	Availability
Note: This schedule applies across our East, West and Mount Isa pricing zones. The proposed transitional network tariffs described in 6.3.1.4 will be available in the East pricing zone only.			

6.2.5 Load control tariffs implementation strategy

Our current load control tariffs are secondary tariffs which can only be used by SAC Small customers in conjunction with a primary tariff.

We are of the view that load control is an important tool in network management and provides benefits to all customers in the form of improved utilisation of network assets. As a result, and in alignment with our customers' expectations, our strategy for the 2020-25 regulatory control period and beyond is to continue to offer relevant load control services to customers that complement our existing and proposed demand and ToU Energy tariffs.

In addition, a primary load control tariff is proposed to be offered to SAC Small business customers for the first time. A primary and secondary load control tariff is also proposed for SAC Large customers.

The rationale for these new business load control tariffs is provided in section 6.3.1.3 and 6.3.2.1 of these Explanatory Notes.

6.3 Rationale for the new 2020-25 tariff structures

The section below details our approach in setting the charging parameters for the new cost reflective tariffs.

6.3.1 SAC Small Customers

A suite of three new tariffs is proposed for both residential and small business new customers with digital metering – a Transitional Demand, Demand, ToU Energy tariff and a suite of transitional ToU energy tariffs to underpin new retail tariffs which will be replacing the transitional retail tariffs to be revoked on 1 July 2021. In addition, it is proposed that small business customers can access a new primary load control tariff.

6.3.1.1 Transitional Demand and Demand Tariffs

The Transitional Demand and Demand Tariff structures are the same and proposed as:

- Demand charge within an evening window (4pm to 9pm) ($/kW/month)
- Fixed charge ($/day)
- Volume charge ($/kWh)

In this tariff the kW demand charge is used to recover LRMC.

6.3.1.2 Time of Use Energy Tariffs

The Time of Use Energy (ToU) Tariff structures are the same and proposed as:

- Fixed charge ($/day)
- Volume charge daytime ($/kWh)

- Volume charge evening ($/kWh)
- Volume charge overnight ($/kWh)

6.3.1.3 Primary load control tariff

The small business primary load control tariff structure is proposed as:

- Fixed charge ($/day)
- Volume charge ($/kWh)

The AER's draft determination provided in-principle agreement to the introduction of a new SAC Small Load Control Primary Tariff, subject to Ergon Energy providing additional substantiation regarding potential bill savings and eligibility criteria.

Many of Ergon Energy's residential customers (320,000) customers already have a secondary controlled load tariff in addition to their primary tariff. These controlled load tariffs offer a lower volume rate compared to the primary tariff for the heating of hot water outside of peak times as controlled by Ergon Energy.

In contrast, the proposed new controlled load tariff for SAC Small customers will be a primary tariff. Ergon Energy intends that typical applications of this primary tariff will be single relatively large loads like irrigation pumps and motors, with their own NMI, that can be interrupted as required by Ergon Energy. These proposed tariffs can:

- deliver substantially more load under control per customer compared to residential customers;
- are only suitable for loads that can be interrupted and leverage existing investment in network related systems; and
- encourage continued connection of high-volume energy loads, which maintains downward pressure on network tariffs overall.

6.3.1.4 Transitional Network tariffs

Two transitional network ToU energy tariffs are proposed to be offered on a strictly limited access basis. These ToU energy tariffs would only be available to SAC Small Customers.

The Time of Use Energy Tariff structure is proposed as:

- Fixed charge ($/day)
- 3 Part Time of Use Volume charges ($/kWh).

In addition a fixed dual-rate demand tariff is proposed to be offered on a strictly limited access basis.

6.3.1.5 Wide Inclining Fixed Tariff (WIFT)

We have introduced the wide inclining fixed tariff which establishes a structure for SAC Small Business customers with basic meters that can close the gap in network charges between customers consuming annual energy around the 100MWh SAC Small – SAC Large boundary. The fixed charge in this tariff increases in 20,000 kWh per annum usage. The structure is consistent with the relationship of increased capacity requirements associated with more energy consumption, more efficient and lower risk residual recovery associated with higher energy consumption and aligns with anticipated future capacity tariffs.

The existing legacy tariffs have been maintained for basic meter customers with consumption less than 20,000 kWh's per annum. This split is a response to stakeholder feedback seeking to minimise the number of customers that are changing tariffs as consumption moves around the threshold and is intended to avoid the transaction costs incurred. This approach also limits the number of customers that are impacted by the introduction of the WIFT structure.

6.3.1.6 Retirement of SAC Small STOUD and STOUe tariffs

We are proposing to retire the SAC Small STOUe and STOUD tariffs from 1 July 2020. These tariffs introduced inclusion of transparent seasonal price signals to SAC Small customers. The tariffs incorporated longer peak seasonal windows (particularly for business) and introduced measurement of demand over the length of the full peak window rather than as measured in a single half hour period within the peak window.

The level of SAC Small customer uptake of these tariffs has been low, as has retailer appetite to build retail tariffs that reflect these structures and take them to the market. The tariffs have a level of complexity that is different to the tariffs more broadly deployed in Australia as a result of the seasonal granularity, the way demand was measured and seasonal weighting of residual recovery. These structures are out of step with the majority of tariffs offered by our peers. Making changes to greater structural alignment in Queensland and nationally is seen as a positive in terms of facilitating retailers efficiently offering cost-reflective tariffs structures. Offering the TOU energy, Transitional Demand and Demand tariff suite and retirement of the STOUe and STOUD are consistent with this alignment.

We further consider that to continue to offer the STOUe and STOUD tariffs which are not consistent with our view of the characteristics of future capacity based structures risks leading customers down a tariff learning and response pathway which will not be sustained and any responses or investment they may make to the structure and rates could be stranded.

To support simplicity both in the tariff structures offered, consistency between tariff options (e.g. peak windows), and manageable numbers of tariffs we do not intend to continue to offer these tariffs.

6.3.1.7 Retirement of SAC Small Residential Lifestyle tariffs

As noted in our June 2019 TSS based on customer engagement feedback we have decided not to proceed with Lifestyle Package tariffs in 2020-25. Both Energex and Ergon Energy introduced trial lifestyle tariffs in 2018 and there has been very little retail or customer response to the tariffs.

To support simplicity both in the tariff structures offered, consistency between tariff options (e.g. peak windows), and manageable numbers of tariffs we do not intend to continue to offer the lifestyle tariff.

6.3.2 SAC Large Customers

6.3.2.1 New load control tariffs

Based on customer feedback there is significant interest from a number of sectors at the SAC Large level to access both primary and secondary load control network tariffs. Consultation feedback also indicated a preference amongst stakeholders that the SAC Large load control network tariffs be available across the network, not just in areas of network constraint.

Consequently, Ergon Energy proposes a new SAC Large Primary Load Control Tariff with the following structure:

- Fixed chare ($/day)
- Volume charge ($/kWh)

The new SAC Large Secondary Load Control Tariff structure is proposed as:

- Volume charge ($/kWh)

The fixed plus volume structure for the primary load control tariff and volume only structure for the secondary tariff option have been adopted to align with the SAC Small Load Control Tariff structures. and therefore provide less complexity for both customers and retailers in terms of implementation and adoption of these tariffs.

6.3.2.2 Rationale for the new load control tariffs

Ergon Energy and Energex's current application of load control through tariffs is predominantly to SAC Small customers, mostly residential customers – with the most common equipment types controlled being hot water systems, pool pumps and air conditioners (particularly in north Queensland).

However, in response to customer interest in exploring both primary and secondary load control network tariff options, Ergon Energy implemented load control tariffs with non-residential customers and non-traditional equipment types as part of the *Agricultural Tariff Trial* which commenced in 2017, with support from the Queensland Government and key industry sector groups (Cotton Australia; Canegrowers; Bundaberg Regional Irrigators Group; Qld Farmers Federation).

The key participants in these trials were mostly agricultural customers operating irrigation pumps in order to assess the suitability for them to operate under controlled tariffs. The *Agricultural Tariff Trial* and the ensuing *Tariff Initiative for Irrigators* involved moving around 70 irrigation pumps sites onto a load control tariff (being economy Tariff 33). This resulted in the following learnings:

- Participating customers were generally able to adjust to occasional load control exercised under the tariff during the trial periods.
- Providing education to customers on how load control tariffs operate was key to ensuring customers could make a sensible choice to move to this tariff option or choose not to.
- The standard tariff option for customers is to move to Tariff 33 as a secondary tariff and it typically requires three extra devices to be installed in the meter box (a utility meter, load control receiver and a customer supplied 'contactor'). This 'two tariff and two meter' tariff combination proved to be a barrier for many customer due to the lack of space in meter boxes. Where the connection point has a single load (i.e. pump), the primary tariff meter has little or no load running through it anyway.
- Regardless of these meter box issues, the minimum cost to move to load control was around $1,500 per site (involving the installation of the contactor which is required for pumps above around 10kW).
- A solution to address the meter box space constraint issues, as proposed in the Ergon Energy and Energex TSS, is to allow customers to access load control as a primary tariff, negating the need for and cost of the second meter.

Whilst there are many customer operations that are not suitable to operate under a load control tariff arrangement, we believe expanding the availability of load control tariffs to SAC Large customers will provide large customers with an additional tariff option to consider as either a primary or secondary tariff.

Currently large customers who use more than 100 MWh/year are not eligible for load control tariffs, even though the nature of their operation (i.e. size of equipment, connection type, suitability for load control etc) can be identical to or more significant than SAC Small customers.

Offering a load control tariff option to SAC Large customers can provide Ergon Energy a low-cost demand management response to constraints that are driven by non-residential (business) loads and complement the proposed ToU energy and demand tariffs for the customer.

Ergon Energy has the capability of interrupting a controlled load during system peak events, and as such limit or avoid its contribution to peak load which is the key driver of LRMC associated with future network augmentation. Controlled load tariff rates will in the first instance reflect that the load is not presenting at peak and therefore it is not appropriate to incorporate LRMC price signals in the tariff. Further, the energy rate can then be set on a basis that recovers residual costs in a way that is attractive to customers to adopt given the reduced level of supply flexibility and associated limitations that they are agreeing to. In return the distributor is securing revenue associated with this load (e.g load control tariffs assists customers economic decision to choose electricity as the energy option they adopt to meet there water heating needs) and the system benefits that the significant amount of controlled load offers in terms of operational flexibility and reduced capacity requirements.

Extension of the availability of load control to SAC Large will assist us with addressing a drop-off of load control customers of approximately 1% per annum from our traditional, mostly residential sources, which is weakening our ability to respond to network events, such as peak demand, loss of reserve and other outage events.

We also have feeders with peak demand driven by non-domestic loads (includes some feeders with higher penetration of irrigation loads) which our traditional load control tariff-based solutions typically don't address – a large customer load control tariff can be a low-cost demand management solution in these situations, particularly given the size of non-domestic loads that may wish to move to this tariff (i.e. 50kW+) compared to far smaller loads for domestic load control tariffs (ie typical range 1 – 3.6 kW).

6.3.2.3 New load control tariffs customer impacts

From a customer perspective the fixed plus flat nature of the load control tariffs will be matched with a demand tariff where it is used as a secondary tariff or compared to a demand tariff if use as an alternative primary tariff is contemplated by the customer. This means the attractiveness of the load control tariff does have a relationship with the customers load factor on their existing tariff. Customers with a high load factor achieve an effective low cost per kWh on the demand tariff structures and will typically not find the load control tariffs attractive. Customers with a low load factor are more likely to find the load control tariffs as an attractive alternative.

Graphs showing the distribution of indicative customer impacts for these tariffs are in Attachment C. Actual customer impacts are likely to be more nuanced as customers identify optimal outcomes between retaining load on the primary tariff and transferring some load to the load control option (similar to how the tariffs are combined by SAC Small customers). While the load control tariffs are not attractive for all customers, these tariffs provide an additional option for customers, are simple and offer value to the network associated with both maximum demand mitigation and flexibility around restoration of controlled load to support maintenance of system load during times of maximum solar generation.

Essentially the load control tariffs are expected to be most attractive to customers who are paying more on a per kWh basis on the demand tariffs, while those who's loads are well suited to the demand tariff structures are more likely to choose to remain of their existing tariff.

We anticipate that customers will mainly be interested in the secondary version of the tariff reflecting that typically customers will not have loads where it is operationally convenient for the entire load to be interrupted. Optimal customer outcomes are expected to reflect a combination of controlled and uncontrolled load, but offering the primary version means that if individual circumstances lead to a preference for the primary version (as has emerged for a small number of SAC Small customers) a version of the controlled load tariff is available to accommodate this preference.

Similar terms and conditions to those that apply to the SAC Small version of the tariff will be applied to the SAC Large versions of the tariff. Extension of the tariff to larger loads does however mean that the nature and scale of the impact of an individual customers controlled load on the local network can be material. To ensure that controlled load is compatible and value adding to the network, approval for access to the tariff will be subject to specific Network requirements. Principally the three main conditions on which approval will be based are:

- signalling ability (customer must be in an area where we are able to remove/reinstate supply through the standard load control signalling technology)
- load control technology compatibility (the equipment to be connected must be suitable to be controlled through interface with the standard network device to the customer supplied contactor)
- no/low risk adverse network impact (including but not limited to the nature/size of the load or in consideration of existing load control customers in the same network area.

This approval requirement has similarities to the approach adopted with respect to the connection of distributed generation to the network.

6.3.2.4 Adoption of kVA Anytime Demand tariff

We are proposing to implement kVA denomination of demand charging for all SAC Large tariffs from 1 July 2020.

This change was foreshadowed in our 2017-2020 TSS with continued consultation undertaken in preparation of the current TSS.

Our modelling of the impact of the change from moving to 2019-20 kW denominated tariffs to the equivalent 2020-21 kVA denominated tariffs is shown in Attachment C (SAC Large customer impact.

Overall 98 percent of the circa 6500 SAC Large customers modelled will experience a reduction in their network tariff in 2020-21. The actual individual customer change will vary with the customers power factor, but overall modelling shows Demand Small tariff customers will experience a reduction of 13.8 percent, Demand Medium tariff customers will receive a 9.6 percent reduction and Demand Large tariff customers a 10.8 percent reduction. A total of five customers have been identified as having an increase of greater than 10% in 2020-21 based on their profile data. These increases reflect outlier positions with respect to power factor. The levels of power factor recorded for these customers are well outside of compliance requirements. The relationship between customer impact and power factor means that individual customer impact can be mitigated through action to improve power factor, in particular achievement of power factor compliance is consistent with these impacted customers receiving significant savings while reducing their capacity requirements on the network.

The anytime energy demand tariffs will be offered on a kVA chargeable demand basis, however where customer metering does not support kVA billing data being available, a kW denominated version of the tariff will continue to be available. Access to the kW demand charge tariff will be based on the capability of the Customer’s metering. We consider this kW variant to the tariff to be transitional to support the restrictions of the current metering fleet and will progressively become redundant as customer metering capability changes over time.

The proposed new ToU Demand tariff for SAC Large customers will be offered on a kVA demand basis only.

The thresholds for each of the Demand Small, Demand Medium and Demand Large tariffs have been increased to reflect typical differences between demand measured in kW and kVA and are now set at levels of 450kVA, 135kVA and 35kVA respectively. The threshold represent the level of demand that is deducted from the customers actual monthly maximum demand to determine the billable demand quantity.

Adoption of kVA based demand meanscustomers will be offered a more cost reflective tariff and provided with incentives to improve their power factor and reduce their electricity network charges and the overall cost of supply from the network Customer impact mitigates are principally the calibration of the tariff rates so that virtually all customers are better off without any change to their current power factor outcomes, and in the small number of instances where increases are anticipated, these can be mitigated by addressing the power factor. Additionally

Ergon Energy's network price structure for SAC Large customers will then align with that of Energex and other distributors throughout the NEM reducing complexity for retailers and customers associated with variation between different parts of Queensland or the national market..

6.3.3 Connection Asset Customers (CAC) and Individually Calculated Customers (ICC)

6.3.3.1 Removal of Excess kVAr charge

We do not propose to initiate any changes to the current structure of the CAC or ICC tariffs during the 2020-25 regulatory control period other than the removal of the excess kVAr charge.

We introduced Excess kVAr billing for Individually Calculated Customers (ICC) in 2015-16. Because of the relatively large number of these customers that had embedded generators, a number of exceptions were needed and changes were made both to the kVA billing and the Excess kVAr billing processes in the following year:

- kVA charges were set to zero for intervals when kW was imported into the network, and
- Excess kVAr charges were based on exceedance of the permitted capacity at compliant power factor, rather than on the actual demand at compliant power factor.

We extended Excess kVAr billing to Connection Asset Customers (CAC) customers in 2017-18.

The Excess kVAr rate for customers is currently $4.00/kVAr/month. This rate is based on an assessment of the hurdle rate to induce customers to install power factor correction at their premises.

The objective of the Excess kVAr program was to reduce the incidence of non-compliance with the power factor provisions of the NER. It was intended to target only those customers that are non-compliant.

The modifications to the original charging process that were necessary to accommodate customers with embedded generation, primarily in changing the kVAr threshold from that allowable at a compliant power factor to the maximum at the customers' authorised demand, significantly reduced the incentive properties of this charge.

This is further highlighted by the relatively small quantum of the Excess kVAr charge we recover, which is now around $450,000 per annum, which is not material compared to the total revenue recovery of the CAC and ICC user groups.

Added to this, it is apparent that since the introduction of kVA billing there has been a steady improvement in the average power factor, as customers adapt to the new charging regime and take steps to minimise their demand charges.

In view of the above analysis and the desire to align network tariffs across the Queensland distribution networks we consulted with customers on the opportunity to retire the Excess kVAr charge from 1 July 2020. Alternative views were expressed by customers, but most of the feedback agreed with retirement of the charge.

Accordingly we propose to retire the excess kVAr charge from July 2020.

6.3.3.2 Locational Charges

We are aware that the AER expects that future cost reflective network tariffs will have a locational component as well as a peak time dimension. The basis of this is the LRMC of augmentation varies between different locations and that efficient tariffs would reflect this variation and make the locational cost transparent to customers.

The most value associated with locational signals is where the network is capacity constrained and customer responses to the high short-run costs associated with the particular location can enable substantial network investment value through deferral. These are the locations which are typically targeted by specific DM initiatives that will communicate the value of the location to customers and the market. Through this period, we will support the SCS tariffs with a suite of customer enabling mechanisms, which is consistent with our view that tariff reform is more than just introducing new tariffs.

Leading into the 2020-25 regulatory control period, implementation of locational tariffs in our network is viewed as introducing a level of complexity and new tariff dynamics across the supply chain that neither networks, retailers nor customers are seeking and which currently offer very little potential for benefit being realised. Locational LRMC is inherently unstable and can change very quickly. A major customer or development can change a location from unconstrained to constrained unpredictably which immediately impacts on the correct locational tariff. Between the TSS submission in January 2019 and its final year of application in 2025 the optimal locational tariff at a single location could swing widely as a result of actions of existing customers or plans of new customers.

While we accept value in providing transparency through to the market of cost of augmentation in constrained areas, the predictability that is implicit in the TSS construct does not translate to the dynamic realities of locational tariff setting.

We propose to achieve locational signals through overlaying locational DM initiatives that value and target specific locational value over the network tariff signals. This approach supports locational pricing that can adapt to evolving network circumstances and needs and can be accurately targeted, calibrated at the known opportunity value, and specifically harmonised in terms of the times, location, structure and tariff levels that optimises the network outcome. In the 2020-25 regulatory control period the SCS network tariff underlay dominates the signal through to the market.

6.4 Assignment of customers to tariff classes and tariffs

We consider the usage profile of customers in the assignment to tariff classes. In accordance with clause 6.18.4(a)(3) of the NER, we do not treat customers with micro-generation facilities less favourably than customers without such facilities but with a similar load profile in assigning customers to tariff classes. Our tariff class and tariff assignment procedures are detailed in Chapter 6 of the TSS.

6.5 Indicative pricing schedule for SCS

In accordance with the NER requirements, we have developed an indicative pricing schedule for SCS for each year of the 2020-25 regulatory control period. The indicative pricing schedule is included in Attachment A of the TSS.

It is important to note that these indicative charges are not the actual charges that a customer will pay each year but rather are intended to provide a robust guide to the likely charges. Actual tariffs may vary from the indicative tariffs in the TSS due to a variety of reasons such as under or over revenue collection in any individual year, future regulatory decisions for transmission revenue or successful cost pass through applications.

Actual charges experienced by our customers will depend on a number of factors outside of our control, including the consumption profile of each customer and the manner in which retailers pass through network charges to the customers in retail tariffs.

In addition, under the maximum revenue cap applied to our revenues earned from providing SCS, annual actual charges will differ from the indicative charges in the TSS to the extent that the electricity consumption and demand assumptions upon which the latter charges are based differ from the actual electricity consumed by customers.

For these reasons, we emphasise that the network tariffs presented are indicative only, not binding and are for the purposes of providing a high level overview of the expected distribution network bill impact for customers for the 2020-25 regulatory control period. Existing network tariff charges should not be extrapolated by the indicative annual charge increases without considering the impact of retailer strategies, customer adoption of alternative tariffs, changes to electricity usage or incentives provided to customers beyond our control in relation to how they consume electricity.

7 COMPLIANCE WITH PRICING PRINCIPLES

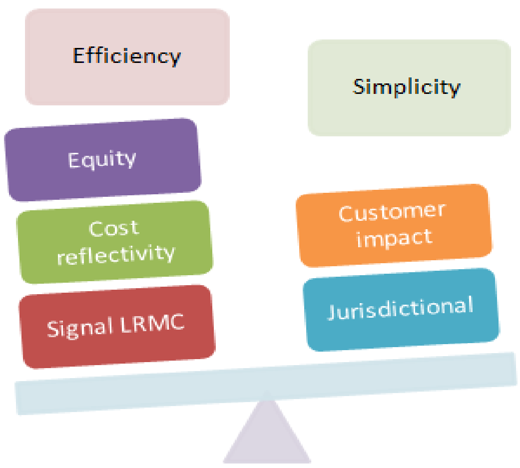
In complying with the pricing principles, we must meet the Network Pricing Objective, which is that the tariffs a distribution network service provider (DNSP) charges in respect of its provision of direct control services to a customer should reflect the DNSP's efficient costs of providing those services.

Clause 6.18.1A(b) of the NER requires that a TSS must comply with the pricing principles which are provided for 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)
- Tariffs must be based on the LRMC of providing the service
- Tariffs must be designed to recover our efficient costs of providing network services in a way that minimises distortions to the tariff signals
- We must consider the impact on customers of changes in tariffs from the previous year and may vary from the pricing principles after a reasonable period of transition to the extent necessary to mitigate the impact of changes, and
- The structure of each tariff must be reasonably capable of being understood by customers having regard to the customer types, feedback resulting from the engagement with customers and compliance with all the other pricing principles.

In some cases, the pricing principles may conflict or compete with each other. As noted by Deloitte, "each tariff design has its own strengths and weaknesses and it is unlikely that any particular tariff design will perform well against every factor or every circumstance".[24]

Figure 10 - Pricing principles



We consulted on the following principles during our engagement with customers on the TSS when designing and developing network tariffs:

[24] Deloitte Access Economics, Residential electricity tariff review – Report commissioned by the Energy Supply Association of Australia, Final Report, 22 January 2014.

- **Economic efficiency** – network tariffs signal the economic costs of providing distribution services to the market
- **Customer impacts –** we manage changes that are expected to affect customer bills for example progressive deployment of changes to avoid bill shock
- **Simplicity and transparency** – we offer customers a clear and simple tariff structure
- **Flexibility** – we provide innovative tariffs that support customer choice and control
- **Fairness** – similar customers pay similar tariffs and charges reflect the impact of customer usage and technology decisions on network costs
- **Stability –** bills should remain reasonably predictable and avoid bill shocks
- **Sustainability –** supports the energy tri-lemma strategy, and
- **Compliance –** network tariffs comply with all relevant regulations and the NER.

Respondents to our customer engagement were very clear in their priorities in regard to principles to be considered in developing the reform agenda that:

- Protection of their constituent's position is a priority - including access, safety and network security, and
- Affordability, equity, transparency are also high priorities.

Respondents did have differing perspectives on what equity means to them.

The NER allows departure from the pricing principles to the minimum extent necessary to meet the consumer impact pricing principle or jurisdictional obligations.[25]

Compliance with the NER pricing principles is further discussed in the sections below.

7.1 Stand-alone and Avoidable cost

Our Distribution Cost of Supply (DCOS) model that is used to calculate network tariffs generates DUOS tariffs based on the full distribution of the building block costs (plus adjustments) that form the total allowed revenue approved by the AER.

The Avoidable and Stand-alone cost methodology described below is used to calculate the revenues for each SCS tariff class associated with each cost. These costs are compared with the weighted average revenue derived from our proposed tariffs.

7.1.1 Definition of Avoidable and Stand-alone costs

These two categories of cost may be defined for tariff classes, as follows:

- The **Avoidable cost** for a tariff class is the reduction in network cost that would take place if the tariff class were not supplied (whilst all other tariff classes remained supplied). If customers were to be charged below the Avoidable cost, it would be economically beneficial for the business to stop supplying the customers, as the associated costs would exceed the revenue obtained from the customer, and
- The **Stand-alone cost** for a tariff class is the cost of supplying only the tariff class concerned, with all other tariff classes not being supplied. If customers were to pay above the Stand-alone cost, then it would be economically beneficial for customers to switch to an alternative

[25] NER, clause 6.18.5(c).

provider. It would also be economically feasible for an alternative service provider to operate. This creates the possibility of inefficient bypass of the existing infrastructure.

There are two alternative concepts that could be used to calculate these costs:

- To ignore the sunk nature of the existing network and estimate the costs which would be associated with an optimally designed network, constructed to supply SCS to the tariff class or classes concerned, or
- To base the estimation of costs on the modification of the existing network to provide SCS to the tariff class or classes concerned.

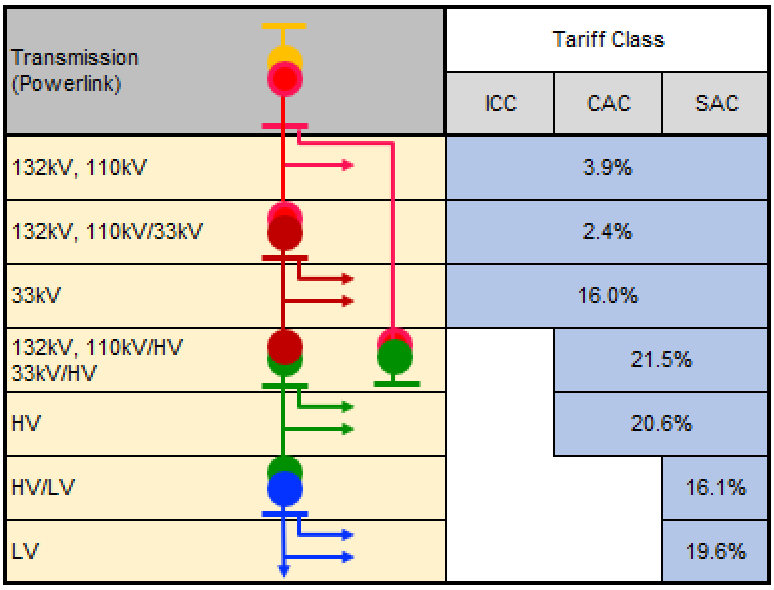
The NER does not prescribe the methodology that should be used to calculate the Stand-alone and Avoidable costs of tariff classes of the network. We have chosen to base our cost estimations on the second concept, based on the hypothetical modification of the existing network, rather than by devising and costing optimal new network structures. This has been done for two reasons:

- To avoid the very substantial resource requirements that would be involved in a full network redesign, and
- In recognition that the economic regulatory framework for distribution supports the existence and value of existing (sunk) network investments and does not support the optimisation of existing networks.

The approach that we have adopted is consistent the approach adopted by Energex. In our case the approach is the same as that which was employed during the 2015-20 regulatory control period, and subsequently approved by the AER.

The DCOS model is also used to estimate the Stand-alone and Avoidable costs for each tariff class, in the manner described below.

Figure 11 – Cost allocation for Stand-Alone and Avoidable network costs



To the right of the figure above, there is a schematic illustration of the connectivity of the network between the successive system levels, from transmission through sub-transmission to HV and thence to LV.

Replacement asset costs have been used in this model as the basis for the cost allocation to tariff classes and to determine the avoidable and Stand-alone cost proportions. The proportions of asset costs associated with each level of the network are also shown.

We have changed the tariff classes used in the 2017-20 TSS period to create a simplified grouping of three tariff classes that align with those of Energex. The system connection voltage level of the constituent tariffs that make up the three tariff classes is shown in the table below:

Table 8 – System connection level of tariffs forming the tariff classes

System Connection	ICC	CAC	SAC
132, 110kV	X	X	
66,33 kV	X	X	
22, 11kV Bus	X	X	
22, 11kV Line		X	X
LV Bus			X
LV line			X

7.1.2 Lower bound test (Avoidable cost)

We estimate the avoidable that cost by responding to the following questions:

> *"If the ICC/CAC/SAC tariff class was not connected to the network, what assets would not be required? If these assets are not required, what revenue should not be collected?"*

The network was assumed to remain in its current state with supply voltages unchanged. Individual classes of assets and their associated costs were 'optimised' by removing a proportion of those costs to reflect the fact the demand is notionally reduced for each tariff class not supplied, whilst still maintaining the same standard of network service for the remaining tariff groups.

Figure 12 – Avoidable network cost calculation

Transmission (Powerlink)	Tariff Class		
	ICC	CAC	SAC
132kV, 110kV		-5.0%	
132kV, 110kV/33kV		-5.0%	
33kV		-5.0%	
132kV, 110kV/HV 33kV/HV		-5.0%	
HV		-7.0%	
HV/LV			
LV			

Figure 12 above illustrates the hypothetical proportions of network assets that would be avoided if the CAC tariff class were to be removed, this is repeated for each of the other tariff classes in turn. The associated percentages express the Avoidable cost as a proportion of the total revenue recovered through the tariff class. For each tariff class, the Avoidable cost is less than the tariff class revenue and the tariff classes are therefore compliant with the NER.

7.1.3 Upper bound test (Stand-alone cost)

Our estimate of the stand-alone cost was determined from a similar assessment of the network capability, in response to the following questions:

> *"If only one tariff class were to be supplied, what assets would be required to supply only this tariff class? If only these assets are required, what revenue would need to be collected?"*

As before, the network is assumed to remain in its current state with supply voltages unchanged. Individual classes of assets and their associated costs are 'optimised' by removing a capacity-based proportion, whilst still notionally retaining the necessary capacity and reliable supply to just the tariff class concerned.

Figure 13 – Stand-alone network cost calculation

Transmission (Powerlink)	Tariff Class		
	ICC	CAC	SAC
132kV, 110kV		80.0%	
132kV, 110kV/33kV		80.0%	
33kV		80.0%	
132kV, 110kV/HV 33kV/HV		80.0%	
HV		80.0%	
HV/LV			
LV			

In Figure 13 above, the columns contain the hypothetical proportions of network assets that would be required if only one of the three tariff classes were to be supplied, in turn. The associated totals in each row express the stand-alone cost as a proportion of the revenue recovered from the tariff. For each tariff class, the stand-alone cost is greater than the tariff class revenue and the tariff class is therefore compliant with the NER.

7.2 Long run marginal cost

We have estimated the LRMC values at each major voltage level of its network for use as the basis of network tariffs, as required by clause 6.18.5(f) of the NER.

In essence the calculated LRMC provides a cost reflectivity target. Tariffs would trend towards the target subject to other pricing considerations. As such, it targets lower network and customer costs and has economic efficiency as its overriding objective. The use of the network LRMC for pricing is required by the NER.

The following is a description of how our LRMC has been estimated using a Long Run Incremental Cost (LRIC) model, similar to that developed by the Energy Networks Association (UK) and approved by Ofgem, their industry regulator.[26,27]

7.2.1 Alternative LRMC calculation approaches

There are three generally accepted methods of estimating the LRMC for network businesses. These are:

- The Average Incremental Cost (AIC) approach, in which the growth-related components of current expenditure and demand forecasts provide the cost estimate

[26] Energy Networks Association (UK), *CDCM model user manual Model Version: CDCM model user manual Model Version: 103,* 28 August 2015.
[27] Ofgem, *Electricity distribution structure of charges: the common distribution charging methodology at lower voltages, Decision Document Ref: 140/09*, 20 November 2009.

- The Perturbation or “Turvey” approach, in which the altered capital and operating costs associated with a hypothetical permanent change in demand provide the basis for the cost estimate, and
- The LRIC approach calculates the annualised cost of the next proposed investment to meet an increment in demand. The most relevant example of this approach is the Common Distribution Charging Methodology (CDCM), which has formed the basis for distribution tariffs in the United Kingdom for many years. This methodology more commonly known as the 500MW model.

To date, we (and other DNSPs in the NEM) have used an AIC model. However, there are a number of issues that make the continuation of this approach problematic. In summary, these are:

- The model is based on a 5 to 10-year regulatory forecast of demand growth and the related associated incremental capital and operating costs prepared for the AER’s Determination. These truncated forecasts are subject to cyclical variation associated with the longer actual investment cycle and variation in factors such as planning risk which, if not moderated, leads to unstable estimation of the LRMC. This can be due to the “lumpiness” and infrequent nature of major capital expenditure, prevailing economic conditions and fluctuations in customer connections and development
- The 2020-25 regulatory control period is a time of overall low demand growth and low capital expenditure and therefore the LRMC in $/kW has a small numerator and small denominator. The calculation becomes numerically unstable in these circumstances and can inaccurately estimate the LRMC, and
- The net demand growth comprises new and modified connections, offset to an extent by disconnections and the reduction in demand at some existing premises. A proportion of replacement capital expenditure also provides additional useable capacity. Applying engineering judgement introduces a level of subjectivity that can be pivotal to the LRMC outcome, but at times of low demand growth and expenditure these adjustments can constitute a significant component of the resultant LRMC.

The Perturbation approach has the disadvantage that it effectively requires re-estimation of the capital and operating expenditure programs for a large number of assumed demand growth scenarios. This calculation is thus resource-intensive.

The following section describes the implementation of the third approach, LRIC, to our network. This is a modelling approach which is similar to that used in the UK sometimes termed the “500MW model”.

7.2.2 The LRIC model

This model is based upon the creation of a hypothetical optimised network scaled to supply a total coincident demand of 500MW, using “building blocks” comprised of modern equivalent assets. These elements embody the current planning standards, spatial characteristics, standardised equipment, average route lengths, and utilisation levels typical for our network. The model effectively replicates a scaled version of the existing network fully representative of its underlying characteristics.

For example, at the 132 or 110kV zone substation level, a generic zone substation based on recently constructed projects is used. This is depicted below.

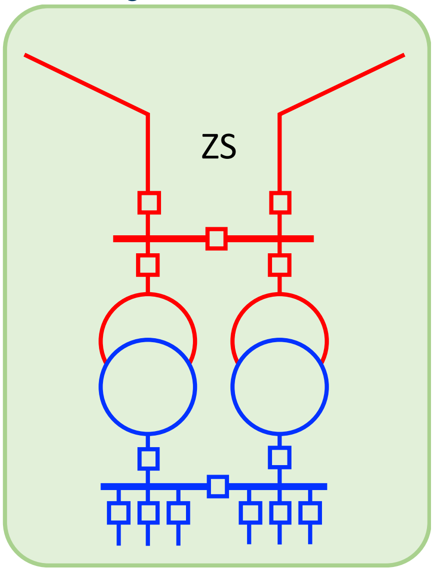
A zone substation building block comprises the following elements:

- Upstream 132/110kV feeders of average number and length, and with the average underground to overhead proportions applicable to our network, and
- Typical layout including busbars, transformers of the usual modern rating and a typical number of outgoing feeder circuit breakers.

Similar building blocks are created for each of the following system elements, in each case including their upstream feeders:

- 132 or 110kV/66 or 33kV sub-transmission substation (rural and urban)
- 66 or 33kV/HV zone substation (rural and urban)
- 132 and 110kV/HV zone substations (rural and urban)
- HV network (rural, urban and remote rural), and
- HV/LV substation (kiosk and pole top).

Figure 14 - Zone Substation Block Diagram

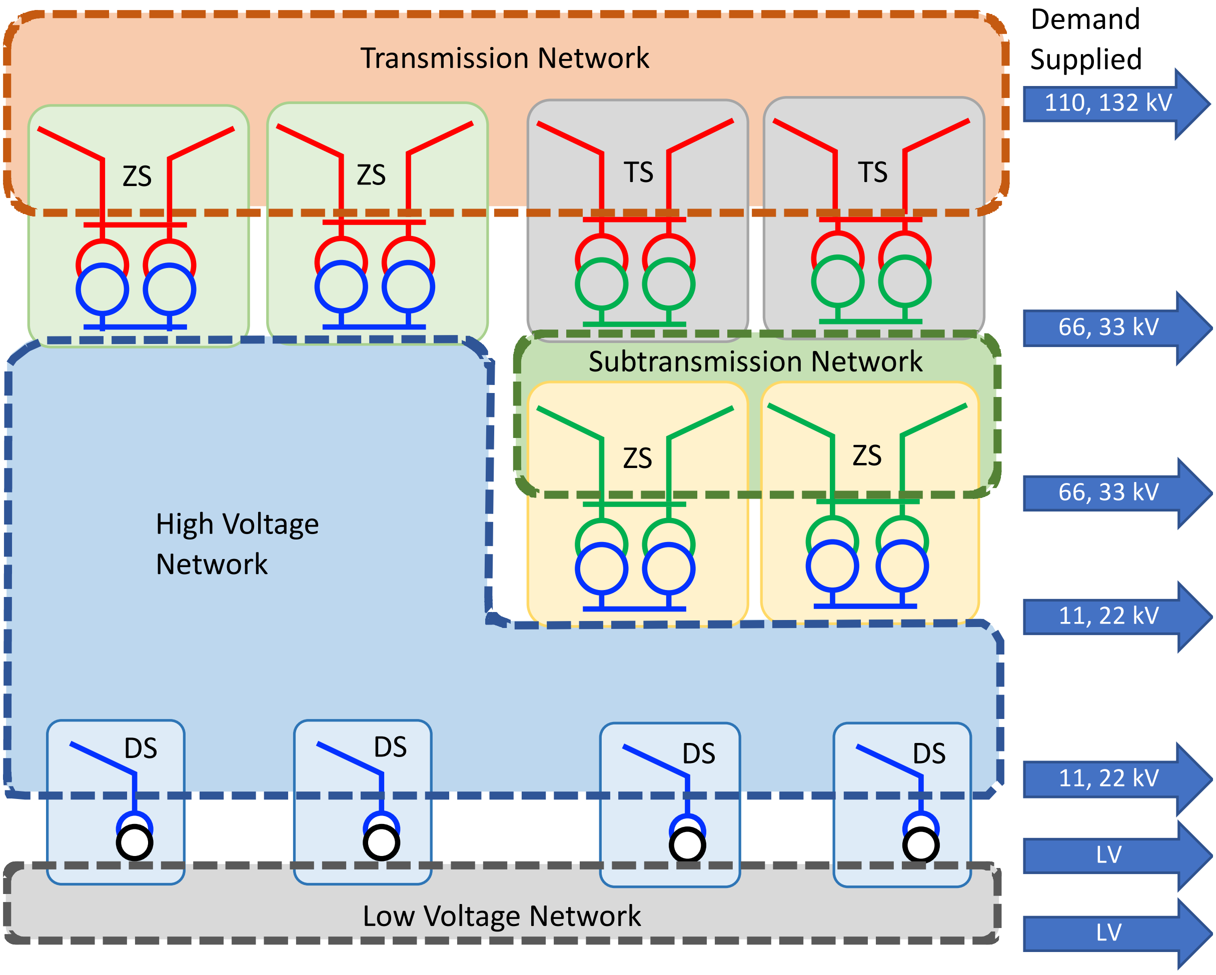


The LV network is also included in the model, on a similar basis (same length/capacity and overhead/underground ratios) as for the existing network. Each building block is assigned a capacity that can include emergency ratings and load transfers, reflecting our normal practice in managing contingencies. The replacement cost of each building block has been estimated from the cost of recent and current capital works.

7.2.3 Structure of LRIC model

The building blocks are then assembled into a hypothetical network capable of supplying a total demand of 500MW, apportioned between system voltage levels in the same ratio as for our network. The figure below depicts the assemblage of building blocks. The number of building blocks of each type is determined by their net capacity and the demand that is supplied through the downstream levels of the network. Whilst the UK model uses integral numbers of building blocks, we use fractions of blocks, to avoid step variations in cost arising from the demand assumptions. This also enables costs to be calculated for areas such as our West and Mount Isa pricing zones, which have relatively small demand.

Figure 15 - LRIC Building Blocks



This LRIC model is in effect an optimal representation of the network, using modern equipment and construction techniques. The model preserves the average spatial characteristics and technical requirements (e.g. optimal equipment capacities) of our network.

The demand connected at each voltage level matches our our network profile, using the coincident peak demand for the system, and is scaled to 500MW. There is no spare capacity within this optimal network, which is created to just match the demand.

The maximum coincident demand of 500MW for the model was chosen in the UK to represent a material demand increase and, by being uniform, to facilitate comparisons between their 14 DNSPs. This demand of 500MW has been retained for our models.

7.2.4 Cost estimates

The Optimised Replacement Cost of the assets that form the building blocks provide the basis for their cost estimate, using the real weighted average cost of capital and standard asset lives determined by the AER. To this is added a standardised allowance for operation and maintenance, expressed as a percentage of the asset replacement costs.

Consistent cost estimates have been developed for line and substation costs. These estimates reasonably represent the cost that would be incurred in greenfield construction of the associated asset. They include the capitalised overheads that would be included in an asset that was incorporated in the RAB. Land and easement values have not included in developing these cost estimates. Line and cable costs in particular were chosen to represent the cost of reasonable-sized projects, rather than a scaling-up of short-length projects with relatively high unit costs.

7.2.5 Voltage level LRMC estimates

The resultant hypothetical network costs were allocated to the system voltage levels and the throughput of each system level in kW was then used to determine an average $/kW for each voltage level. For example, sub-transmission substation costs were allocated downstream to sub-transmission, HV and LV levels.

These $/kW costs were applied to the Coincident Demand supplied by us to determine the LRMC expressed in $/kW/annum at each voltage level. Finally, the average power factor at each voltage level was used to determine the LRMC values, expressed in $/kVA/annum, that apply to the coincident demand at that voltage level.

7.2.6 Tariff level estimates

The LRIC model does not convert the LRMC rates into tariff quantities such as demand and peak energy rates. Rather, voltage level LRMC rates are taken into DCOS, where the tariff level conversions are performed.

The form of conversion to tariff rates within DCOS depends upon the peak period charge through which the LRMC is recovered. In broad terms, the impact of the tariff on the network's cost through its contribution to the coincident peak demand is calculated in dollar per annum terms. That dollar amount is recovered through the tariff rate (e.g. $/kVA or kW, $/MW) subject to considerations of the individual customer impact.

In applying the LRMC estimates to the rate setting process we have continued our approach of considering the LRMC as a cost reflectivity target, rather than a binding figure that peak charging parameters must equal. In a number of tariffs the LRMC is recovered at a rate that is lower than the LRMC estimate. This provision for transitioning is most explicit in the SAC Small transitional demand rates where the demand charge has been deliberately calibrated to manage the customer impact that flows from the intention to assign customers on digital meters to cost reflective tariffs. Offering the transitional demand tariff as the default for these customers with an initial low demand rate (that will increase over time) will maximise transfer of customers to cost reflective structures with little impact on their network charges during a period when current network augmentation projection requirements are subdued.

The SAC Small transitional demand tariff is complemented by the Demand tariff option which recovers a higher level of LRMC in the demand charge and is expected to be of interest to customers with higher existing load factors and/or are motivated to respond to the demand price signal.

7.2.7 Model Outcomes and Comparison with 2017-20 rates

LRMC values per annum at each major voltage level of its network (sub-transmission, HV and LV) are set out in the table below:

Table 9 – Comparison of Proposed 2020-21 and current 2018-19 LRMC values by voltage levels (Nominal)

Ergon Energy East and Mount Isa

Voltage Level	LRMC 2020-21 $/kVA/annum	LRMC 2018-19 $/kVA/annum

132/110/66kV/33kV	$72	$33
22/11kV	$141	$175
LV East	$226	$255
LV Mount Isa	$103	

Notes:
- The figures are undiversified
- The figures are exclusive of GST.

Ergon Energy West

Voltage Level	LRMC 2020-21 $/kVA/annum	LRMC 2018-19 $/kVA/annum
132/110/66kV/33kV	$107	$93
22/11kV	$360	$437
LV	$660	$638

Notes:
- The figures are undiversified
- The figures are exclusive of GST.

It is proposed that the LRMC values will be adjusted by CPI throughout the 2020-25 regulatory control period.

7.3 Managing customer impacts

EQL considers price impacts to be the highest priority in the transitioning of customers to more cost reflective tariffs over the 2020-25 regulatory control period. To this end, our proposed new tariffs and associated tariff assignment processes have been developed closely in accordance with clause 6.18.5(h) of the NER. It requires that we must consider the impact on customers of changes in tariffs and may vary the tariffs to the extent we consider reasonably necessary, having regard to:

- The desirability that tariffs comply with the pricing principles after a reasonable period of transition
- The extent to which customers can choose the tariff to which they are assigned, and
- The extent to which customers are able to mitigate the impact of changes in tariffs.

The AER noted in its Draft Determination on our June 2019 TSSs that the customer impact principle provides guidance on how distribution networks should mitigate customer impacts if it is necessary to do so given their circumstances, such as by transitioning prices to efficient levels over time and providing customers with more tariff choices.[28]

Following submittal of our June 2019 TSSs, EQL engaged UNSW and CSIRO to undertake detailed distributional bill impact analysis of our proposed network tariff reforms. This analysis has allowed us to present robust evidence of the customer impact of the proposed tariff reforms and the extent that our customers are able to mitigate these impacts by switching to alternative primary tariffs or opting into new controlled load tariffs.

In this regard, we understand that a move to new tariff structures and cost reflective tariffs will impact customers differently and as such, we have developed a suite of new tariffs to provide our diverse customer base with choices, flexibility, cost savings and the opportunity to gain more value from our

[28] AER, Attachment 18 – Tariff structure statement, Draft decision - Energex 2020–25, p 14

network. Of most importance, most customers on Ergon Energy network tariffs will benefit from a price reduction in 2020/21 arising from our lower allowable revenues reflecting network efficiencies. Further, the charging components in our new cost reflective tariffs have been designed to appeal to customers by being set at a differential relative to less cost reflective legacy tariffs[29].

For example, the transitional demand tariffs for new Residential and Small Business customers incorporates a muted peak demand price signal compared to the standard demand tariffs to allow these customers to adjust to tariffs they may not be familiar with and/or to mitigate the potential for network charge impact. This means most new Residential and Small Business customers assigned to the transitional demand tariffs will be better off than being assigned to the less cost reflective legacy tariffs. Further, Residential and Small Business customers with good load factors will benefit by choosing to opt in to the new standard demand tariffs. Similarly, new customers assigned to the transitional demand tariff are free to opt-in to the new ToU energy tariff if that better suits their needs and/or is easier for them to understand. Regardless, the transitional demand tariffs have been designed in a way that will facilitate the transition to cost reflective tariffs in a timely manner without causing adverse customer bill impacts.

We are also proposing to grant a 12-month grace period for Residential and Small Business customers with digital meters who are still assigned to less cost reflective legacy tariffs before they are re-assigned to the new transitional demand tariffs. We consider this reasonably balances the transitioning of customers to cost reflective tariffs while mitigating the potential for bill impact in making this transition.

In terms of providing greater choice for customers, including to lower their electricity bills, for Small and Large SAC customers, we have proposed new primary load control tariffs that will provide them with the option of avoiding demand tariffs in return for Ergon Energy managing their load to mitigate network demand peaks. For customers with flexible business operations and associated energy requirements, this is likely to be an attractive tariff option.

Finally, as a key part of the transitioning to cost reflective network tariffs, Ergon Energy will work with retailers and other relevant parties to educate customers on these new tariffs, in particular, to better manage the impact on specific vulnerable customer cohorts. To this end, it is envisaged that customers will be given access to information necessary for them to make informed tariff choices and decisions about upgrading their appliance mix, investigating in solar PV and other DER, and how best to sustainably modify their electricity usage to fully benefit from the incentives available under the more cost reflective demand tariff structures.

The following sections provide a customer impact assessment of our proposed network tariff reforms using the most up-to-date indicative charges and details how customers who do choose to adopt demand tariffs can respond through usage behavioural change and technology adoption.

7.3.1 Customer Impact Modelling outcomes

For both modelling rates and assessing customer impact outcomes, we utilise customer samples. Samples have been developed for residential, small business and business customers individually. Each sample is designed to provide statistical information on the load profiles of the customers that make up the sample. The design needs to ensure that the sample provides a statistically sound

[29] It is important to note that our distribution network price reductions, as set out in section 6.3 of our TSS Explanatory Notes for residential and small business customers, will also be experienced by those regional Queensland customers on notified retail prices, as a result of the Queensland Government's uniform tariff policy.

representation of the relevant customer population. It also needs to be statistically efficient so that the sample can provide the best accuracy of the estimated loads given the number of customers in the sample.

Each customer included in the samples has a scaling factor applied indicating how many “like” customers they portray. This enables us to scale outcomes in our modelling, but to streamline presentation, we have omitted this scaling factor from our charts. We also review representative customers (average and median customer bill) to assist communicating customer impacts to customers. The sample sets were drawn from customers with interval data.

Ergon Energy is proposing to introduce a new suite of cost reflective tariffs for its customers. As the tariffs consist of maximum demand related charges, or energy as a proxy for demand in the case of the ToU energy tariff, half-hourly load profiles for individual customers have become essential inputs into network pricing modelling as well as their customer bill impacts.

We recognise that customers and stakeholders are seeking more granular customer impact analysis to inform their assessment of our proposed network tariffs, and that this feedback has been clearly stated in responses provided to the AER’s Issues Paper consultation in May 2019. We have responded to this feedback by commissioning the University of New South Wales (UNSW), and the Commonwealth Scientific and Industrial Research Organisation (CSIRO) to greatly expand the level of customer impact analysis in line with the direct feedback provided by customers and stakeholders to date. Outcomes of this analysis will be presented to customers and stakeholders prior to the AER’s Final Determination and the full customer impact report developed by UNSW has been submitted as part of our Revised TSS (Attachment B) and is available on our Talking Energy webpage.[30]

A SAC Large customer impact summary undertaken by Ergon Energy is provided in our Revised TSS (Attachment C). Extracts from this summary were discussed with stakeholders at our November 21 Deep Dive consultation event. Customer impacts are presented using the 2019-20 anytime demand tariffs as the baseline position.

7.4 Stakeholder Engagement

Please refer to *Tariff Structure Statement 2020-25 Engagement Summary* for a summary of the outcomes from our detailed customer and stakeholder engagement undertaken as we developed our TSS documents. A summary of a selection of responses of a technical nature are included in Appendix A of these Explanatory Notes.

[30] University of New South Wales, Customer Impact Analysis for Energy Queensland’s Revised Tariff Structure Statement 2020-25. November 2019.

8 ALTERNATIVE CONTROL SERVICES

Services provided under the ACS framework are customer specific or customer requested services. These services may also have potential for provision on a competitive basis rather than by a single DNSP. ACS are akin to a 'user-pays' system. The full cost of the service is paid by those customers who benefit from the service, rather than recovered from all customers.

Consistent with the F&A, all ACS are subject to a price cap control mechanism. Our ACS include:

- Connection services (i.e. excluding those services classified as SCS in the F&A)
- Network Ancillary Services
- Metering Services – which include Type 6 (default) Metering Services and Auxiliary Metering Services (the F&A refers to these as Type 5 and 6 Metering Services, but Type 5 meters are not permitted in Queensland and for clarity we refer to these only as Type 6 Metering Services), and
- Public Lighting Services.

Type 6 metering services, public lighting services and fee-based ancillary and connection services have been calculated in accordance with the formula set out in Figure 2.2 of the F&A, and our quoted services (services of a nature and scope which cannot be known in advance) will be calculated in accordance with the formula set out in Figure 2.3 of the F&A.

8.1 ACS Classification of Services

For the 2020-25 regulatory control period, we have largely adopted the AER's Service Classification Guideline and aligned our ACS tariff groups with the AER's Draft Decision in relation to Classification of services. Our ACS tariff groups are described in the table below:

Table 10 - ACS tariff groups

Tariff Group	Description
Connection services	ACS Connection services encompass: • activities to facilitate major customer connections to the network, • connection application and management services which are specific to a connection point and • enhanced connection services which are provided at the request of a customer or a third party.
Ancillary network services	Ancillary network services include services which are not covered by another service and are not required for the efficient management of the network, or to satisfy DNSP purposes or obligations.
Metering services	**Type 6 Metering service** Metering services encompass the metering installation, provision, maintenance, reading and data services of Type 6 metering. **Auxiliary Metering services** Includes work initiated by a customer which is specific to a metering point.
Public lighting	Public lighting services relate to the provision, construction and maintenance of public lighting assets owned by us (conveyance of electricity to public lights remains an SCS). Includes energy efficient retrofits and new public lighting technologies, including trials.

8.2 Connection services and Network ancillary services

The lists of tariff classes and services which fall under the connection services and Network ancillary services classification are listed in the table below. Consistent with the approach adopted for other ACS, services have been determined to be fee-based or quoted depending on whether the scope of work is pre-defined or subject to variability.

Table 11 – Connection and Network ancillary services and charging arrangements

Tariff class	Service	Service description	Charging arrangements
Connection services – Services relating to the electrical or physical connection of a customer to the network			
Major customer – Premises connections	Connection services for major customers	Additions or upgrades to connection assets locate on the customer's premises for major customers. Includes Standard connection services and Negotiated connection services.	Quoted
Major customer – Network extensions	Extension to connect a new or altered major customer	Enhancement required to connect a power line or facility outside the present boundaries of the transmission or distribution network owned or operated by a network service provider to facilitate new or altered major customer connection. Includes Standard connection services and Negotiated connection services.	Quoted
Connection application and management services	Protection and power quality assessment prior to connection	Investigation into Power Quality issues including Flicker, Harmonics and DC voltage injection.	Quoted
Connection application and management services	Preparation of preliminary designs and planning reports General evaluation and advisory service	Preparation of preliminary planning and design reports for major customer connections, including project scopes and estimates. Includes general evaluation and advice on asset ownership options, indicative estimates of viable connection options, and recommendation on the most suitable option.	Quoted
Connection application and management services	Application assessment	Assessing an application requesting a connection to be made (or altered) between the distribution network and the customer's installation, and the costs associated with negotiating and preparing a negotiated connection offer.	Quoted
Connection application and management services	Site inspections	Site inspection in order to determine nature of connection being sought.	Quoted
Connection application and management services	Connection advice	Provision of connection advice, assessment and data requests for site-specific connections (during the connection enquiry and/or connection application stage), including: • Embedded generation assessments • Advice on project feasibility • Concept scoping	Quoted

Tariff class	Service	Service description	Charging arrangements
		• Project estimation • Advice on whether augmentation would likely be required • Capacity information, including specific network capacity • Load profiles for load flow studies • Requests to review reports and designs prepared by external consultants, prior to lodgement of connection application, and • Additional or more detailed specification and design options. Provision of advice, design and specification on request to an applicant considering a build-own-operate asset ownership option for connection assets. Detailed enquiry response fee - Costs associated with preparing a detailed enquiry response pursuant to Chapter 5 of the NER.	
Connection application and management services	Assistance with a tender process	Applies where the DNSP conducts a tender process on behalf of a connection applicant to procure connection services that can be provided by a third party, or where the connection applicant conducts a tender process and requires assistance from the DNSP.	Quoted
Connection application and management services	Temporary connection	Customer requested temporary connection (short term) and the recovery of the temporary builders supply. Excludes work on metering equipment. Note: In non-grid connected areas of our network (isolated feeders and Mount Isa-Cloncurry supply network) this service may include work on metering equipment.	Fee-based
Connection application and management services	De-energisations	Retailer requests de-energisation of the customer’s premises where the de-energisation can be performed at the premises by a method other than main switch seal (i.e. at pillar box, pit or pole top) Retailer Requested de-energisation (Main Switch Seal – MSS)	Fee-based Fee-based
Connection application and management services	Re-energisations	Retailer requests re-energisation of the customer's premises where the customer has not paid their electricity account. No visual required. Retailer requests re-energisation for the customer's premises following a main switch seal (no visual required). Retailer or metering coordinator/provider requests a visual examination upon re-	Fee-based Fee-based Fee-based

Tariff class	Service	Service description	Charging arrangements
		energisation (physical) of the customer's premises. Retailer requests a visual examination upon re-energisation (physical) of the customer's premises where the customer has not paid their electricity account. NMI de-energised > 30 days.	Fee-based
Connection application and management services	Supply Enhancement	Service upgrade. For example, an upgrade from single phase to multi phase and/or increase capacity. Applies to underground and overhead service upgrades. Excludes work on metering equipment (if required). Overhead/Underground.	Fee-based
Connection application and management services	Supply Abolishment	Retailer requests us to abolish supply at a connection point and decommission a NMI. May be used where a property is to be demolished; supply is no longer required; an alternative connection point is to be used; or a redundant supply is to be removed. Overhead/Underground.	Fee-based
Connection application and management services	Point of attachment relocation	Customer requests their existing overhead service to be replaced or relocated, e.g.as a result of point of attachment relocation. No material change to load. This includes De-energisation, followed by physical dismantling then reattachment of service and re-energisation. Excludes work on metering equipment (if required).	Fee-based
Connection application and management services	Re-arrange connection assets at customer's request	Rearrange connection assets at customer's request - simple (upgrade from overhead to underground where main connection point is in existence). Recovery of the overhead service and connection of the consumer mains to the pre-existing pillar for a customer requested conversion of existing overhead service to underground service.	Fee-based
Connection application and management services	Temporary disconnections and reconnections	Temporary de-energisation and re-energisation of supply to allow customer or contractor to work close - the service may be physically dismantled or disconnected (e.g. overhead service dropped). This service includes switching if required.	Fee-based
Enhanced connection services	Customer or third party requested services to provide different quality of reliability standards	Other or enhanced connection services including those that are: • Provided with a higher quality of reliability standards, or lower quality of reliability standards (where permissible) than required by the NER or any other applicable regulatory instruments • In excess of levels of services required to	Quoted

Tariff class	Service	Service description	Charging arrangements
		be provided by the distributors • For embedded generators, including removal of network constraints	
Network ancillary services – Services related to common distribution services but for which a separate charge applies			
Network related property services	Property tenure services	Network related property services such as property tenure services relating to providing advice on, or obtaining: deeds of agreement, deeds of indemnity, leases, easements or other property tenure in relation to property rights associated with a connection or relocation Conveyancing inquiry services relating to the provision of property conveyancing information at the request of a customer.	Quoted
Network safety services	Provision of traffic control and safety observer services Fitting of tiger tails and aerial markers De-energising for safety High load escorts	Third party and customer requested services requested for safe approach Installation of aerial markers (or Powerlink Hazard Identifiers) on overhead lines.	Quoted
Sale of approved materials or equipment	Materials/equipment sales	Includes the sale of approved materials/equipment to third parties for connection assets that are gifted back to become part of the shared distribution network.	Quoted
Customer requested planned interruptions	Customer requested planned network outages	Includes: • Where the customer requests to move a distributor planned interruption and agrees to fund the additional cost of performing this distribution service outside of normal business hours • customer initiated network outage (e.g. to allow customer and/or contractor to perform maintenance on the customer's assets, work close to or for safe approach, which impacts other networks users).	Quoted
Attendance at customers' premises to perform a statutory right where access is prevented.	Statutory right access	A follow up attendance at a customer's premises to perform a statutory right where access was prevented or declined by the customer on the initial visit.	Quoted
Inspection and auditing services	Auditing services	Auditing / re-inspecting of connection assets after energisation – real estate developments Number of new, modified or recovered sites	Quoted
Provision of training to third parties for network	Training services	Training services provided to third parties that result in a set of learning outcomes that are required to obtain a distribution network	Quoted

Tariff class	Service	Service description	Charging arrangements
related access		access authorisation specific to a distributor's network. Such learning outcomes may include those necessary to demonstrate competency in the distributor's electrical safety rules, to hold an access authority on the distributor's network and to carry out switching on the distributor's network.	
Authorisation and approval of third-party service providers design and works	Accreditation of design consultants Accreditation of alternative service providers	Accreditation and approval of alternative service providers to provide design and construction services for real estate development and/or provide construction services for real estate development. Service includes: • Desktop management services evaluation • Onsite management system evaluation • Capability evaluation	Quoted
Security lights	Installation service Maintenance, operation and replacement service	Provision, installation, operation and maintenance of equipment mounted on a distribution equipment used for security services, e.g. night watchman lights.	Quoted Fee-based
Removal/rearrangement of network assets	Customer initiated network asset relocations / re-arrangements Switching Cable bundling	Removal, relocation or rearrangement of network assets (other than connection assets) at customer request that would not otherwise have been required for the efficient management of the network.	Quoted
Customer requested provision of electricity network data	Data provision services	Customer requests provision of electricity network data requiring customised investigation, analysis or technical input (e.g. requests for pole assess information and zone substation data).	Quoted
Third party funded network alternations	Third party funded network alternations	Alterations or other improvements to the shared distribution network to enable third party infrastructure to be installed on the shared distribution network. This does not relate to upstream distribution network augmentation.	Quoted

8.3 Metering services

8.3.1 Type 6 (default) Metering services

Type 6 metering services refer to the recovery of capital cost of existing Type 6 metering equipment and the ongoing maintenance, meter reading and meter data services for Type 6 meters.

It should be noted with Power of Choice taking effect in Queensland on 1 December 2017, we are no longer responsible for providing metering installations as they are subject to contestability. We are only able to provide metering services to existing regulated meters as long as they are in operation. As a result, on 1 December 2017, a number of ACS were either discontinued or had the metering provision component separated from the service with the remaining service components covering the services still performed by us. However, in the Power of Choice exempt areas (Mount Isa-Cloncurry and Isolated supply networks) we remain responsible for the installation and replacement of metering equipment.

8.3.2 Auxiliary metering services

Auxiliary metering services are customer requested metering services provided to individual customers on a non-routine basis. The scope of auxiliary metering services currently involves a number of services including meter alterations, Type 6 non-standard metering services, off-cycle meter reads, meter tests (customer initiated), meter inspections and meter reconfigurations.

8.3.3 Pricing methodology

The table below summarises the classification of metering services for the 2020-25 regulatory control period.

Table 12 - Classification of Ergon Energy's metering services

Metering services	Service description	Method giving effect to Price Cap	Charging arrangements
Type 6 Metering Services	Routine meter maintenance, meter reading and meter data services for Type 6 meters and the recovery of capital costs related to existing Type 6 meters.	Limited Building Block	Annual metering services charge comprising of capital and non-capital components
Auxiliary Metering Services	The following customer requested metering services which are provided to individual customers on a non-routine basis: • Meter inspection and investigation • Meter reconfiguration • Meter alteration • Reseal • Meter test • Meter reading • Removal of meter (Type 6) • Type 6 non-standard metering data services • Install new meter (Type 6)	Cost build up approach	Fee based – a formula-based approach in the first year and then a price path for the remaining years of the regulatory control period.
Provision of services for approved unmetered supplies	Provision of services to extend / augment the network, to make supply available for the connection of approved unmetered equipment, e.g. public telephones, streetlights, extension to the network to provide a point of supply for a billboard & city cycle, e.g. Installation of a pillar to supply connection for R3 public lighting.	Cost build up approach	Quoted

Pricing methodology used to calculated the Type 6 (Default) Metering Service Charges

Our proposed annual Type 6 metering service charges have been set based on the required revenue each year, the cost allocation weighting between primary, controlled load and solar metering services, and the forecast number of services each year. Further details on the default Type 6 metering building blocks are provided in our 2020-25 Regulatory Proposal.

The relative costs are based on the net present value of forecast ACS Type 6 metering capex and opex, weighted by the cost allocation between primary, controlled and solar metering services.

The annual indicative Type 6 metering charges for 2020-21 included in the TSS are calculated by dividing the revenue requirement for primary, controlled load and solar services by the volume of services in each of these tariff categories. The primary plus controlled load charge assumes one controlled load only. Each additional controlled load would incur an incremental charge. The primary with solar charge incorporates the primary service charge. We are of the view that the proposed charges for annual ACS Type 6 metering services are consistent with the NER, being between the Stand-alone and Avoidable cost of the service.

For subsequent years of the regulatory control period, we have used the formula set out in Figure 2.2 of the F&A to calculate the charges for Type 6 metering services. Note that the value for A_t^i in the formula set out in Figure 2.2.of the F&A has been set to zero for each year of the 2020-25 regulatory control period. In accordance with the AER's Draft Determination, the X-factors for metering services for the remaining years after the first year of the regulatory period (2020-21) have been set to zero and prices are only escalated for inflation.

Pricing methodology used to calculate the Auxiliary Metering Services charges

The methodology used to calculate the charges for auxiliary metering services is the same as that used for other fee-based services and quoted services, that is, a cost build-up approach using the AER's prescribed formulas

8.4 Public lighting

The provision, construction and maintenance of public lighting assets, as well as emerging public lighting technology and other public lighting services, are classified as a direct control service and further as an ACS under a price cap form of control. The conveyance of electricity to public lights (unmetered supply) will continue to be classified as a SCS.[31] The list of public lighting services and control mechanisms are listed in Table 13 below:

Table 13 - Ergon Energy's control mechanisms for public lighting services

Public lighting service	Service description	Method giving effect to Price Cap	Charging arrangements
Provision, construction and maintenance of public lighting	**Conventional and LED lights:** Non-contributed (EOO): • NPL1 Major: high watt • NPL1 Minor: low watt Contributed (GOO): • NPL2 Major (high watt) • NPL2 Minor (low watt)	Limited Building Block	Public light daily fixed fee

[31] It should be noted that, in line with the AER's Draft Determination, we have removed the placeholder proposal for a public lighting metered supply tariff in the event of a future amendment to the metrology requirements set out in the NER.

Public lighting service	Service description	Method giving effect to Price Cap	Charging arrangements
	LED only lights: Contributed (GOO) • NPL4 Major (high watt) • NPL4 Minor (low watt)		
Auxiliary public lighting services			
Other public lighting services	Construction of new public light services (contributed)	Cost build up approach	Quoted
	Provision of unique luminaire glare screening or other customer requests	Cost build up approach	Quoted
	Review, inspection and auditing of design or construction works carried out by an accredited service provider undertaking 3rd party works.	Cost build up approach	Quoted
	Relocation, rearrangement or removal of existing public light assets and energy efficient retrofit.	Cost build up approach	Quoted
	Exit fee for the residual asset value of non-contributed public lights when the entire assets (pole, cabling, bracket, luminaire and lamp) are replaced before the end of their expected life	Cost build up approach	Quoted
Emerging public lighting services	New public lighting technologies including trials	Cost build up approach	Quoted

Methodology underpinning the charges for the provision, construction and maintenance of public lighting

Our approach to calculating the public lighting tariffs for 2020-25 broadly aligns with the approach used in the 2015-20 regulatory control period. There are some differences that reflect the introduction of the LED tariffs and the new NPL4 tariff. These differences include:

- The use of separate revenue building blocks for conventional public lights and LEDs, and
- The separate calculation of the NPL4 tariff.

The forecast revenue requirement to be recovered for the provision, construction and maintenance of public lighting over the 2020-25 regulatory control period has been determined based on the AER's Post Tax Revenue Model (PTRM) for conventional and LED public lighting assets. Refer to our 2020-25 Regulatory Proposal for further details on the revenue for public lighting services.

<u>Separate calculation of the NPL4 tariff:</u>

In line with customer expectations, we are proposing to introduce a new public lighting tariff, NPL4 that will apply for assets where customers fund the replacement of the NPL1 luminaire and lamp to LED, but where the associated pole and cabling are legacy and non-contributed assets. In this respect, NPL4 sits between the NPL1 tariff (where we have funded all assets) and the NPL2 tariff (where the entirety of the public lighting assets is funded by customers).

The calculation of the NPL4 tariff is performed separately from the calculation of the NPL1 and NPL2 (which is set out in the following section) but relies on the outcomes of the NPL1 and NPL2 calculations to ensure the tariff accurately reflects the fact that only the luminaire is gifted to us. This means that:

- The operating cost for public lights which are on NPL4 is set at 90 percent of NPL2 levels. The reason for not including the 10 percent capital component relating to refurbishment of the contributed assets is to support the adoption of LED lights in the early stages of the roll-out. We intend to review this approach in future TSSs.
- The capital cost for public lights which are on NPL4 should only reflect the proportion of public light infrastructure owned by Ergon Energy (i.e. the pole, bracket, cables etc) used for LED lights. The NPL4 tariff can therefore not be set higher than the NPL1 rate, and
- The tax allocation to be applied to the asset cost pool and operating cost pool must reflect the fact that the customer has only gifted the LED luminaire.

This approach aligns with the AER's Draft Determination.

Overarching calculation methodology for NPL1 and NPL2

The approach to calculating the NPL1 and NPL2 tariffs for conventional and LED public lighting is the same, with the only difference being that separate conventional light and LED revenue building blocks are used to determine the respective asset and operating cost pools.

As such, the generic approach used for conventional and LED technologies is set out below:

1. The revenue requirement has been divided into an asset cost pool and operating cost pool
2. Based on historical data, and consistent with the 2015-20 regulatory control period, the factors used to allocate asset pool costs and operating pool costs between major and minor lights have been set at a level that reflects the higher costs associated with major lights
3. A series of charge components are then calculated using the average number of lights in each category for each year of the next regulatory control period as follows:

Table 14 - Public Lighting Charge Components

Price components	NPL 1		NPL 2	
	Major	Minor	Major	Minor
Asset cost pool (original cost)	X	X	-	-
Asset cost pool (refurbishment)	X	X	X	X
Operating cost pool	X	X	X	X

4. The sum of cost components produces charges for each year of the next regulatory control period
5. Using the calculated 2020-21 charges for that year, an X factor is calculated so that charges for subsequent years will change by CPI – X each year, consistent with the formula set out in Figure 2.2 of the F&A, such that the forecast revenue stream produced from the calculated charges from 2020-21 to 2024-25 inclusive equal in net present value terms to the revenue requirement from Step 1, and:

a. Considering the need to manage customer impact the smoothing mechanism starts in Pt-1 (2019-20) for conventional lights32
b. The X factors for the remaining years of the period (2021-2022 to 2024-25) are set at zero. The value for A_t^i in the formula set out in Figure 2.2.of the F&A has been set to zero for each year of the 2020-25 regulatory control period.

It should be noted that public lighting assets (NPL2) will retain their existing funding arrangement classification once they have reached the end of their economic lives and replaced and funded by us. This is made possible by including in the NPL2 rate the revenue relating to an estimated number of contributed public lighting assets which will be replaced during the 2020-25 regulatory control period.

Exit fees

We propose to develop exit fees on a quoted basis based on the written down value of the public lighting assets where the entire public lights (pole, cabling, bracket, luminaire and lamp) are to be replaced before the end of their expected life in circumstances involving relocations or road diversions.

We propose that the replacement of conventional lights with LEDs will not incur an exit fee for the following reasons:

- Generally upgrading to LEDs will not involve a total asset replacement as many poles, cabling, and brackets will be retained
- The replacement of conventional lights with LEDs is likely to only trigger the replacement of the pre-1990 type brackets still in use, which have little or no residual asset value (as their expected life was less than 28 years), and
- This approach will incentivise the uptake of LEDs.

Auxiliary public lighting services

It is proposed to charge auxiliary public lighting services as a quoted service using the cost build-up formula prescribed by the AER.

8.5 Security (watchman) lights

Until the commencement of the 2020-25 regulatory control period security lighting services have been provided as an unregulated service with Ergon Energy having full discretion in relation to the pricing methodology and charges applicable for this service. Ergon have traditionally earned very little revenue from this service.

Ergon Energy's current approach to charging for security lighting services consists of a three-part tariff which includes:

- A one off up-front installation charge ($ per unit) – This charge is designed to recover the operating costs (labour and overheads) which are incurred during installation.
- A fixed on-going daily maintenance, operation and replacement charge ($ per light) – These charges are designed to recover all capital cost (including materials costs associated with the installation and asset replacement) and operating and maintenance expenditure. Capital costs are recovered during the life of the asset. Ergon's maintenance charge varies

[32] For LED lights the smoothing mechanism starts in P_t (2020-21) as there were no LED tariffs in the previous year.

depending on the specific type and size of lamp, with 13 different rates offered corresponding to all the lamp types that are currently active (including those lamps which are no longer available for purchase). The variations in price between the various tariffs are minor, largely reflecting the differences in the lamp replacement costs.

- Estimated energy use charge – This charge is calculated in accordance with the AEMO's published load tables and our AER approved rates for unmetered supply.

As security lighting services are currently unregulated, a profit margin is also applied to all charges.

With security lighting services becoming ACS from 1 July 2020, we are not proposing significant changes to the structure of Ergon Energy's existing tariffs in order to minimise the impact on our customers. We propose to retain the existing three-part charging structure subject to the following changes:

- The up-front installation charge will transition from a 'fixed fee' to a quoted service. The basis for this change is to ensure full cost recovery and to provide flexibility for discounts in prices for multiple unit/light installations.
- The existing on-going maintenance charges will be simplified and rationalised resulting in a reduction from thirteen rates to five new broader categories. For simplicity, the new categories are based on the amount of illumination required and the type of lighting technology (i.e. Small LED, Medium LED, Small conventional, Medium conventional and Large conventional). On 1 July 2020, subject to pre-existing contractual arrangements, existing customers will be re-assigned to one of the five new categories depending on the type of lighting technology and lumen outputs.
- The profit margin applied under the current pricing arrangements will be removed.

The proposed new categories for maintenance, operation and replacement charges are expected to provide Ergon with flexibility to adopt different technologies as they become available. Further, the proposed LED rates are expected to encourage the transition to LED as capital costs are recovered over a longer period (i.e. 10 years for LED vs 3 years for conventional lights which reflects the longer asset life), resulting in the lower charges in comparison to the charges for conventional lights.

8.6 Changes to fee-based services in the Revised TSS

Since we submitted our original TSS in January 2019, we have made minor adjustments to our proposed fee-based services to simplify our service offering by reducing the number of service permutations and to clarify our service descriptions. A summary of the adjustments is provided below:

- The Anytime service option which initially was extended to all fee-based services will now be limited to Re-energisation (for urban and short rural feeder) and Supply Abolishment services (for urban feeder only). The Anytime service option will allow customers to raise a service order requesting that these services be prioritised subject to our crew's availability. The premium service option will incur an extra cost which, for the sake of simplicity, will be set at the same level as the After Hour service option.

- The Meter Only (no travel cost) service option for Supply Abolishment will be charged per NMI rather than per meter as initially proposed. This is to recognise that the incremental cost to remove multiple meters at a single NMI is negligible and a charge per meter may not be justifiable.

- The Meter Only service options for the Supply Abolishment service have been consolidated as the costs for the Overhead and Underground options are identical. This will reduce the number of permutations.

- For re-energisation and de-energisation services requiring a main switch seal (MSS), the permutations with CT and without CT have been consolidated as this distinction is not required for these services.
- A new Supply Abolishment service ‘Request to de-energise an unmetered supply point’ has been added to our fee-based service list. This service can be costed in advance of supply with reasonable certainty and it is therefore more suitable as a fee-based service rather than a quoted service.

APPENDIX A – SELECTED STAKEHOLDER RESPONSES

The table below provides our responses to some of the customer and stakeholder feedback received during our TSS consultation process.

Issues	You Said	We Said
Long Run Marginal Cost (LRMC)	Some stakeholders and customer advocates are concerned with the impact of shifting from volume tariffs to demand tariffs, noting that LRMC is directly linked to the demand charge in cost reflective tariff.	To address concern about a smooth transition to demand based tariffs, we have developed Transitional Demand tariffs with a calibrated LRMC. The lower level of demand is intended to mitigate the cost impact on customers assigned to cost reflective tariff while, at the same time, introduces the new concept of demand. In terms of assignment rules, existing customers with digital metering prior to 1 July 2020 will be given the option to remain on their legacy tariff until 30 June 2021. Finally, customers with digital meters who do not wish to be on a demand based tariff will be provided with the option to opt in the new ToU energy tariff. These measures will ensure that the financial impact small customers may experience is mitigated during the transition to cost reflectivity. These are detailed in Section 3.5 and 3.7 of the Ergon Energy Revised TSS and Section 6.2.4 of the Explanatory Notes.
	Stakeholders and customer advocates asked whether the use of LRMC is appropriate in a low growth period.	Basing our tariffs on LRMC is a requirement of the NER. We recognise that the trend in network cost drivers is gradually shifting away from network peak constraints as a result of emerging changes in customer network utilisation and impact of DER. In recognition of the changes in the underpinning cost drivers, as well as the need to reflect the current network wide capacity and the need to manage customer impact, we are proposing to calibrate the LRMC values during the 2020-25 regulatory control period.
	Tariffs are calculated on the same flawed LRMC estimates.	Please refer to the response above.
	The error of imposing congestion pricing in the absence of congestion is highlighted by the ACCC recommendation in its July 2018 final report Restoring electricity affordability & Australia's competitive advantage	Please refer to the response above.
	Some stakeholders and customer advocates seek efficient tariffs that are reflective of the spare network capacity.	Please refer to the response above.
	Certain load profiles take place outside the summer months, and yet these loads receive only moderate reduction in costs	Please refer to the response as above. We are also proposing to expand our suite of load control tariffs. We have developed new primary and secondary load control tariffs available to SAC Large customers. These tariffs are detailed in Section 4.2 of the Ergon Energy Revised TSS and further are provided in Section 6.2.5 of these Explanatory Notes.
	Certain stakeholders and customer advocates are open to the distribution networks exploring a model that derives an	Our current LRMC methodology is detailed in Section 6.2 of these Explanatory Notes. During the 2020-25 regulatory control period, we intend to

Issues	You Said	We Said
	LRMC on a current and future focussed network.	further explore new approaches to incorporate in the LRMC values the impact of emerging technologies on the network.
Package tariffs	Some stakeholders and customer advocates expressed concerns that if the top-up charges of the Package tariffs are too punitive, then business customers may respond by choosing to secure a higher level of network capacity than necessary in order to avoid large cost spikes if they exceed their band.	Package tariffs are no longer included in the TSS for 2020-25.
	Some stakeholders and customer advocates suggest adjustments to the Lifestyle Package to reduce bill shocks.	Packaged tariffs are no longer included in the TSS for 2020-25.
	While seeing the 'Lifestyle Package' tariff as an improvement on the legacy demand based tariffs, the new tariff is considered as being too complex and likely to result in bill shock.	Packaged tariffs are no longer included in the TSS for 2020-25.
Customer impact	Some stakeholders and customer advocates support a gradual approach to the introduction of cost-reflective tariffs that include customer research (especially of low income and vulnerable customers) and a data sampling period following installation of a digital meter.	The network tariffs and tariff assignment rules have been developed in our updated TSS in recognition of the need to manage customer impact in our journey towards cost reflectivity.
	It is suggested that a safeguard tariff be considered. Such a tariff should be potentially funded from the State's consolidated revenue and not tariffs which are borne by other customers.	We are not in a position to develop such a tariff as it would be unlikely to meet the pricing principles set out in the NER. Financial assistance for customers is a matter for the Queensland Government. We have conveyed the views of stakeholders and customer advocates on this matter to Queensland Government representatives.
DER contribution to network capacity	Stakeholders and customer advocates have commented that embedded micro-generation capacity is forecast to increase. Depending on the rate of increase in this capacity relative to organic demand growth, it is possible that future demand growth is more or less flat indefinitely.	We are carefully considering both the investment required to manage the Low Voltage (LV) network performance given the ubiquitous investment in DER that is occurring and the benefits available to enhance capacity of the network.
Supporting customers	Some stakeholders and customer advocates recommend additional support to assist customers to understand the Lifestyle Package.	Package tariffs are no longer included in the TSS for 2020-25.
Tariff Assignment	Some stakeholders and customer advocates expressed concern that mandatory assignment would take a customer's control away.	The principles of equity and fairness continue to underpin our TSS development. The feedback from the AER, stakeholders, customer advocates and customers on this matter have been reflected in the Revised TSS.
Equity	Large customer advocates are seeking equitable treatment for their customer user group – in terms of a share of savings from reduced overall revenue requirements and removal of cross subsidies.	The reduced revenue requirement will benefit all customer segments, including large customers.

Issues	You Said	We Said
	Some stakeholders and customer advocates are seeking concrete details around the extent of cross-subsidies as well as on the proposed timing to eliminate these cross-subsidies.	We are committed to implementing new and innovative cost reflective tariffs. However, the pace of tariff reform needs to take into account customer impacts and the propensity for customers to adopt changes within a reasonable timeframe. One way to identify the quantum of cross subsidisation is to consider the savings (or costs) in customer bills as a result of changing tariffs from legacy to cost reflective tariffs. To assist stakeholders, customer advocates and customers we have included customer impact analysis in this Explanatory Notes document.
Tariff choice	Agricultural advocates have suggested there is an opportunity around a "genuine optimised control load tariff for crops such as sugar cane".	Broad based primary and secondary load control tariffs are being proposed for SAC Small business and SAC Large customers. We invite stakeholders, customer advocates and customers to provide further feedback on this matter as part of the AER's TSS consultation process.
	Some stakeholders and customer advocates have identified the complexity of understanding the difference between the standing and market offers from each of the retailers in the market. Adding another tariff option in addition to the existing suite of tariffs may escalate the level of complexity of retail market offers.	In offering additional network tariff options, our primary focus is to develop a suite of cost reflective tariffs which provide customers with choice but also to ensure our network tariffs are relevant to our customers' changing needs. We agree that more needs to be done to reduce the risk of confusion for customers. We intend to work collaboratively with energy retailers to ensure education and information material is developed to support customers to make informed tariff choices.
Determination of peak period	Stakeholders and customer advocates recognise that there are periods where the network faces peak demand constraints. However they have requested a review of the original summer peak window dimensions.	Package tariffs are no longer included in the TSS for 2020-25.
Jurisdictional Schemes	Some stakeholders and customer advocates noted that we did not include any allowance for the costs associated with jurisdictional schemes such as the Solar Bonus Scheme.	Jurisdictional scheme amounts are excluded from the calculation of the indicative rates for the 2020-25 regulatory control period included in this TSS.

APPENDIX B – RESPONSES TO AER DRAFT DETERMINATION

Our responses to the AER's TSS Draft Determination - Summary

Issue	AER's draft determination	EQL's position
Overarching strategic tariff issues		
Linkage between tariff reform and broader network planning and demand management initiatives	**Guidance** Greater clarity required to support the tariff reform proposal, particularly in the context of future challenges arising from the increasing penetration of solar PV, electric vehicles and batteries.	**Agree with Draft Determination** Section 4 of the TSS Explanatory Notes provides more details on how EQL's tariff strategy supports network planning and demand management initiatives to address expected network challenges in the 2020-25 regulatory control period and beyond.
Speed of customer transition to cost reflective tariffs	**Guidance** Proposed adoption of cost reflective tariffs as the default for residential and small business customers to facilitate quicker customer transition to cost reflective tariffs while managing associated price impacts.	**Agree with Draft Determination** The default tariffs for new residential and small business customers will be the new Transitional Demand Tariffs from 1 July 2020 (existing customers with digital metering before 1 July 2020 will be permitted to access the IBT until 30 June 2021. Existing residential and small business customers can also opt-in to alternative cost reflective ToU Energy or Demand Tariffs at any time.
Relative price levels of new cost reflective and legacy tariffs	**Guidance** To facilitate the take-up of cost reflective tariffs, they can be set at a discount relative to the less cost reflective legacy tariffs.	**Agree with Draft Determination** The Revised TSS provides for the new default Transitional Demand and ToU Energy Tariffs to be set at a differential rate to the legacy default tariffs. For example, compared to Ergon Energy's IBT, most residential customers are better off under the Transitional Demand and ToU Energy Tariffs (87% and 74% respectively at NUOS level). For small business customers the proportions of customers who are better off increases further for customers consuming 20MWh/annum or more, although this is partially offset by the inclining fixed charge structure of the Wide Inclining Fixed Tariff (WIFT). Compared to the IBT tariff, most small business customers consuming less than 20MWh/year are better off under the Transitional Demand and ToU Energy tariffs (92% and 58% respectively at NUOS level). Compared to the Ergon Energy WIFT, a clear majority of customers are better off under the Transitional Demand, ToU Energy and Demand Tariffs (85%, 87% and 98% respectively at NUOS level). The larger proportion of customers who are better off under the new cost reflective tariffs tend to consume less electricity in peak periods and therefore gain further benefits from these new tariff structures.
Residential tariffs (SAC tariff class) – new cost reflective tariffs, grandfathering and retirement of legacy tariffs		

Issue	AER's draft determination	EQL's position
Residential IBT Proposed in June 2019 TSS as default tariff for residential customers.	**Not approved** Use of a less cost reflective IBT as a default tariff does not comply with the distribution pricing principles. IBTs are not well supported by evidence and based on the weak assumption of a link between a customer's total consumption and the level of capacity demanded by those customers during times of congestion.	**Agree with Draft Determination** The Revised TSS grandfathers the legacy IBT, which will remain open only for existing customers. The IBT will no longer be a default tariff for new customers. The legacy IBT has been grandfathered, rather than retired, because the cost of reassigning customers to a flat tariff and administrative burden of notifying the customer's retailer of the tariff change would outweigh the benefits, particularly given that Ergon Energy residential customers are not exposed to the IBT tariff structure at a retail tariff level.
Residential Transitional Demand Tariff Not originally proposed in June 2019 TSS.	**Guidance** Transition the price level of the demand charging parameter in the proposed Residential Demand Tariff B to LRMC over time (eg over 10 years as per Endeavour Energy).	**Agree with Draft Determination** The Revised TSS provides that the default tariff for new residential customers will be a new Transitional Demand Tariff incorporating a transitional LRMC price signal. The price level of the demand parameter will be managed in a customer impact framework rather than specific period of time.
Residential ToU Energy Tariff Proposed in June 2019 TSS as legacy ToU energy tariff.	**Guidance** Provide residential customers with a choice of cost reflective tariff structure by introducing a new opt-in TOU energy tariff.	**Agree with Draft Determination** A new opt-in ToU Energy Tariff with peak, shoulder and off-peak charging components has been included in the Revised TSS. The Revised TSS also grandfathers the legacy Seasonal ToU Energy Tariff.
Residential Demand Tariff B Proposed in June 2019 TSS as new default tariff for new customers.	**Guidance** Demand tariffs are cost reflective. However, residential customer understanding of this type of tariff is not strong. Transitioning the peak-related demand charging parameter to LRMC over time will facilitate customer understanding of demand tariffs and manage potentially adverse price impacts. Provide residential customers with the choice of an opt-in TOU energy tariff as an alternative to the default demand tariff.	**Agree with Draft Determination** The Revised TSS provides for new opt-in Residential Demand Tariff (without any LRMC transitioning) and ToU Energy Tariffs. As noted above, the new default Transitional Demand Tariff transitions the LRMC price signal managed with a customer impact framework generally in accordance with AER's Draft Decision.
Capacity Tariff Proposed in June 2019 TSS as new opt-in tariff.	**Not approved** Preference for EQL to further engage with customers and use the learnings and empirical evidence from this trial to design a new capacity tariff proposal for the 2025-30 regulatory control period.	**Agree with Draft Determination** EQL will trial capacity tariffs during the 2020-25 regulatory control period.
Secondary Load Control Tariffs Existing tariffs proposed in June 2019 TSS are available on an opt-in basis linked to a customer's	**Approved** Acknowledges EQL's load control capability	**Agree with Draft Determination** No change proposed to proposed Secondary Load Control Tariffs.

Issue	AER's draft determination	EQL's position
primary tariff.		
Legacy ToU Energy and Demand Tariffs These tariffs have been available on an opt-in basis in the 2015-20 regulatory control period.	**Guidance** Refer guidance in rows above regarding development of new cost reflective tariffs.	The Revised TSS retires these legacy tariffs due to low customer take-up and to avoid unnecessary tariff complexity. In addition, the peak charging windows for these legacy tariffs are substantially different to the new cost reflective tariffs e.g. business 10am to 8pm conflicts with new 4pm to 9pm peak charging window.
Legacy Small Business IBT Proposed in June 2019 TSS as default tariff for small business customers. [Ergon Energy only]	**Not approved** For existing small business customers, adopting an IBT structure similar to Endeavour's IBT, could be approved if EQL demonstrates that it will deliver a smoother transition path for larger energy users moving to a more cost reflective demand tariff.	**Agree with Draft Determination** The Revised TSS grandfathers the legacy IBT, which will remain open only for existing small business customers. Existing customers consuming more than 20KWh/year with basic meters will be re-assigned to a new WIFT (refer row below).
New Small Business Wide Inclining Fixed Tariff (WIFT) Not originally proposed in June 2019 TSS.	**Guidance** Consider re-designing the Business IBT (Ergon Energy) and Business Flat Tariff (Energex) to recognise how inclining fixed charges based on escalating consumption levels will assist customer transitioning to the SAC Large Demand Tariff.	**Agree with Draft Determination** The Revised TSS provides that existing small business customers with basic meters consuming more than 20MWh per year will be re-assigned from the Business IBT to this new tariff. The WIFT incorporates inclining fixed charges, with the first fixed charge block set with reference to the Business IBT Tariff to manage customer impacts in the transition.
New Small Business ToU Energy Tariff Not originally proposed in June 2019 TSS. Legacy ToU Energy Tariff to be grandfathered (refer row below).	**Guidance** Provide small business customers with a choice of cost reflective tariff structure by introducing a new opt-in ToU Energy Tariff.	**Agree with Draft Determination** A new opt-in ToU Energy Tariff with peak, shoulder and off-peak charging components has been included in the Revised TSS.
New Small Business Demand Tariff B Proposed in June 2019 TSS as default demand tariff for new customers. Legacy Small Business Demand Tariff to be grandfathered (refer row below).	**Approved** Demand tariffs are cost reflective. However, small business customer understanding of this type of tariff is not strong. Transitioning the peak-related demand charging parameter to LRMC over time will facilitate customer understanding of demand tariffs and manage potentially adverse price impacts. Provide small business customers with the choice of an opt-in TOU energy tariff as an alternative to the default demand tariff.	**Agree with Draft Decision** The Revised TSS includes a new opt-in Demand Tariff (without LRMC transitioning). The new default Transitional Demand Tariff (discussed above) transitions the price level of the demand charging parameter to LRMC within a managed customer impact framework. An opt-in ToU Energy Tariff has also been included in the Revised TSS.
Capacity Tariff Proposed as new opt-in tariff in June 2019 TSS.	**Not approved** Preference for EQL to further engage with customers and develop tariff understanding through trials.	**Agree with Draft Determination** EQL will trial capacity tariffs during the 2020-25 regulatory control period.

Issue	AER's draft determination	EQL's position
New primary and secondary load control tariffs Proposed in June 2019 TSS for small business (SAC Small and SAC Large) customers connected to LV network.	**Guidance** Need to demonstrate the economic rationale for the expansion of controlled load tariffs including**:** • demonstrating how this proposal satisfies the LRMC pricing principle • demonstrating how it contributes to the efficient allocation of residual costs • demonstrating how these tariffs will interact with cost reflective tariffs as more customers will be assigned to these tariffs • providing evidence and customer impact analysis that shows load control tariffs can mitigate the negative impact under cost reflective pricing • providing greater clarity regarding eligibility criteria for this tariff.	**Agree with Draft Determination** Further justification of the economic rationale for these proposed new load control tariffs has been provided in section [6.3.2] of the Revised TSS Explanatory Notes. These tariffs will be available on an opt-in basis for eligible customers. EQL intends that typical applications of the primary tariff will be single relatively large loads like irrigation pumps and motors, with their own NMI, that can be interrupted as required by Ergon Energy. The proposed tariffs incorporate minimal or no LRMC price signal because they are based on controlled off-peak supply. In other words, customers assigned to these tariffs are highly unlikely to contribute to peak network demand. The proposed volume charges in the Ergon Energy primary load control tariffs have been set lower than the volume charges in the new cost reflective demand tariffs to mitigate negative customer impacts.
Legacy seasonal ToU energy and demand tariffs These tariffs have been available on an opt-in basis in the 2015-20 regulatory control period. [Ergon Energy only]	**Not approved** Retiring these legacy tariffs and re-assigning customers to the somewhat less cost reflective new non-seasonal demand tariff is not consistent with distribution pricing principles. To address our concerns, Ergon Energy should not re-assign existing customers in this way. We also consider it appropriate for the existing seasonal ToU and ToU demand tariffs to be available on an opt-in basis to all customers with digital meters.	**Disagree with Draft Determination** The Revised TSS retires these legacy tariffs due to low customer take-up and retailer interest, to avoid unnecessary tariff complexity and inconsistency in peak charging components compared to new cost reflective tariffs. New cost reflective default Transitional Demand and opt-in Demand and ToU Energy tariffs are included in the Revised TSS.
New default Demand Tariff Proposed in June 2019 TSS for SAC Large customers, with legacy demand tariffs available on an opt-in basis, with exception of grandfathering of seasonal demand tariff. [Ergon Energy only]	**Not approved** The existing default tariffs appear superior from an efficiency perspective given that they better reflect the seasonal nature of utilisation on Ergon Energy's network Further information should be provided to demonstrate that the replacement of the existing default Demand Small, Demand Medium and Demand Large Tariffs with the single new default Demand Tariff would not exacerbate the bill impacts associated with customers that exceed the 100 MWh pa tariff threshold.	**Disagree with Draft Determination**
New default demand tariff	**Guidance** Need to demonstrate that the	**Agree with Draft Determination** Implementing transitional approach

Issue	AER's draft determination	EQL's position
Proposed in June 2019 TSS for SAC Large customers, with legacy Small and Large Demand Tariffs remaining available on an opt-in basis. [Energex only]	proposed new default Demand Tariff for SAC Large customers is superior to the legacy demand tariffs. Need to provide further information to demonstrate that the new default Demand Tariff does not exacerbate bill impacts for customers that exceed the 100 MWh pa threshold.	commencing with demand large SAC customers. New demand medium and demand small customers can opt in to the ToU Demand tariff. The UNSW customer impact analysis report is presented in Attachment B of the Revised TSS.
Peak charging windows Peak charging window from 8.00am to 4.00pm was proposed in June 2019 TSS for SAC Business Demand, Capacity and ToU Energy Tariffs and CAC Demand Tariffs.	**Guidance** Use of a morning peak charging window in the proposed cost reflective tariffs is questionable. In contrast, the evening peak charging window (4pm-9pm) is supported by evidence.	**Agree with Draft Determination** Morning peak charging windows have been removed from all relevant cost reflective tariff structures in the Revised TSS. A narrow peak charging window of 4.00pm to 9.00pm is applied in all new relevant cost reflective tariffs. Existing longer peak charging windows apply for legacy CAC and ICC Demand Tariffs.
Allocation of residual costs across tariffs The June 2019 TSS indicated distortions to price signals are minimised by separating charging parameters for LRMC and residual cost recovery. However, this separation is not possible for some legacy and volumetric tariffs.	**Guidance** Need to provide more information on the basis of allocation of residual costs at the individual tariff and individual charging component levels. Provide more evidence to demonstrate the proposed allocation approach minimises the distortion to efficient price signals.	**Consistency with Draft Determination** Residual costs will be recovered through the fixed and volumetric components of the new cost reflective tariffs. In contrast, LRMC will be signalled through peak demand-related charging components of these tariffs. EQL considers that this will minimise the distortion to efficient price signals in these tariffs. This approach is also adopted in CAC and ICC Tariffs. The only tariffs where it is not possible to cleanly separate the LRMC and residual cost recovery charging components are the legacy residential and small business tariffs, which are proposed to be grandfathered.
Estimation of LRMC for inclusion in tariff structures The June 2019 TSS proposed a new methodology for the estimation of LRMC, which is similar to the '500 MW' model some electricity distributors use in the United Kingdom.	**Guidance** Proposed approach to estimate LRMC contributes to compliance with the distribution pricing principles at this stage of the tariff reform process. However, AER has the following concerns regarding EQL's proposed approach: • Excess capacity on the network needs to be better reflected in the LRMC charging components in relevant new cost reflective tariffs. • Transition the LRMC price signal in the Transitional Demand Tariff over a 10 year timeframe (in accordance with Endeavour Energy). • Transition the peak demand charges to LRMC for SAC Large medium and large business customers. • Explore inclusion of repex	**Agree with Draft Determination** EQL's new Transitional Demand Tariffs for residential and small business customers incorporates a transitional LRMC price signal that will be increased based on a customer impact management framework This transitioning effectively reflects excess capacity on the network. EQL will revisit these issues when applying its LRMC methodology in the 2025-30 regulatory control period.

Issue	AER's draft determination	EQL's position
	into the LRMC calculations • Consider implications of stagnant and/or declining demand growth on the distribution networks in the LRMC estimation methodology.	
Compliance with customer impact pricing principle In the June 2019 TSS, customer impact analysis was provided for SAC tariff (Small and Large) customers, including to show implications of the 10,000 kWh wide band in the IBT (for residential customers) and 20,000kWh wide band in IBT (for small business customers). The remaining analysis for SAC Small customers provides population impact for Flat, Demand and Capacity Tariffs.	**Not approved** Customer impact analysis could be improved by including all tariffs and by extending the assessment period to include the annual change in network bills over the full 2020-25 regulatory control period. More detailed analysis of the potential impact under the proposed tariffs for different customer groups, particularly for irrigators, vulnerable customers and customers with solar PV systems could also be provided.	**Agree with Draft Determination** Following submittal of the June 2019 TSSs, EQL engaged UNSW and CSIRO to undertake detailed distributional bill impact analysis of our proposed network tariff reforms. The UNSW customer impact analysis report is presented in Attachment B of the Revised TSS.
Tariff assignment rules - summary		
New residential and small business customers	**Guidance** The proposed assignment of new customers to less cost reflective tariffs is inconsistent with the distribution pricing principles.	**Agree with Draft Determination** The Revised TSS provides for the assignment of new residential and small business customers by default to a new cost reflective Transitional Demand Tariff
Existing residential and small business customers with digital meters The June 2019 TSS proposed re-assignment of existing customers who already have a digital meter to the proposed IBT.	**Not approved** Proposes the re-assignment of existing customers with digital meters to a cost reflective tariff. Suggests changing the proposed customer tariff assignment rules to not allow reversion to non-cost reflective tariffs.	**Disagree with Draft Determination** The Revised TSS proposes to assign existing customers who have a digital meter by default to the transitional demand tariff on 1 July 2021. EQL considers this 12 month grace period provides a reasonable balance between transitioning existing customers to cost reflective tariffs, while balancing customer understanding of new tariffs and potential adverse price impacts. These existing customers can choose to opt-in to the new ToU Energy Tariffs or Demand Tariffs during the 12 month period.
Assignment of existing customers who acquire digital meter after June 2020 The June 2019 TSS proposed assignment to default Demand Tariff.	**Guidance:** Agree with proposed assignment by default to a demand tariff.	**Agree with Draft Determination** Revised TSS provides for assignment of these residential and small business customers to the new Transitional Demand Tariffs upon acquisition of a digital meter.
Assignment of residential hardship customers The June 2019 TSS proposed that hardship	**Guidance** Better justification is required that the proposed assignment complies with the distribution pricing principles, particularly the	**Agree with Draft Determination** The Revised TSS includes a tariff assignment rule to not allow reversion to non-cost reflective tariffs.

Issue	AER's draft determination	EQL's position
customers be allowed to opt-in to the legacy Residential Flat Tariff.	customer impact principle - it is not clear that hardship customers would be worse off being assigned to a cost reflective tariff. The TSS is silent about when these customers will transition to cost reflective tariffs. A more suitable approach is to transition prices to efficient levels over time and to provide tariff choice for these customers.	The outcomes of EQL's post-June 2019 residential customer impact analysis indicates that the average and median bills under all the 2020/21 tariffs are lower than under the 2019/20 tariffs. Of the 2020/21 tariffs, the default Transitional Demand Tariff results in the lowest average and median bills.
New ICC tariff class definition and associated customer assignment approach	**Guidance** Insufficient information is provided relating to the proposed re-assignment of customers of relatively high cost-to-serve to ICC tariffs. Specifically, the AER has requested: • A detailed description of the proposed approach to identifying customers that are an outlier from a cost-to-serve basis • A detailed description of the proposed methodology for estimating the cost-to-serve of an individual customer • An indication of the potential number of customers that could be identified as being 'outliers' from a cost-to-serve perspective and the extent that these customers will be adversely impacted by being re-assigned to a more cost reflective site-specific individually calculated tariff • Detailed description of the measures to mitigate the customer impact of this reassignment • A detailed description of the proposed engagement process with the affected customers • Provide further clarification on the proposed eligibility criteria associated with the ICC tariff class, noting that the current wording could be broadly interpreted to mean that Energex will allow LV customers to be reassigned to the ICC Tariff Class.	**Consistency with Draft Determination** Section 6.2.1 of the Revised TSS Explanatory Notes provides more details on the basis of assignment of CAC customers to the ICC Tariff Class.
Customer engagement		
Outstanding customer engagement issues	**Guidance** Engage with stakeholders about the following matters: • To set the initial price of the evening peak charge in the cost reflective tariffs well	**Consistency with Draft Determination** EQL provided its suite of revised proposed network tariffs for consideration by its customer groups in November 2019. Residential and Large Customer Tariff Structure Statement Forums was also held

Issue	AER's draft determination	EQL's position
	below the LRMC estimate • To work constructively with stakeholders to develop a reasonable transition path for the demand charge, noting that we recently approved a 10 year transition to LRMC for Endeavour Energy • To engage about the introduction of default Transitional Demand Tariff and opt-in TOU Energy Tariff for residential and small business customers • To work with retailers and other relevant parties to educate customers on cost reflective tariffs, particular to better manage impact on vulnerable customer cohorts.	on 21 November to discuss amongst other things the UNSW customer impact analysis.
Education materials for customers	Under EQL's proposed Tariff Education Dynamic Incentive framework, it is envisaged that customers will be given access to the information necessary for them to make informed tariff choices and decisions about upgrading their appliance mix, investigating solar PV and other DER, and how best to sustainably modify their electricity usage to fully benefit from the incentives under the more cost reflective tariff structures.	**Agree with Draft Determination** A range of communications and education materials are being developed to educate customers and assist retailers.