Supporting Information

Revised Tariff Structure Statement 2017 to 2020

October 2016

We embarked on our network tariff reform journey in 2012-13, very much aware we must continue to meet everyone's needs into the future for the best possible price with fairer, more equitable pricing signals. We wanted to give our customers the opportunity to save, but in a way that reduces the costs of supplying energy for everyone.

Ergon Energy is enabling customers with greater choice and control over how they want to use the network while still delivering peace of mind through a safe, dependable electricity service…all for the best possible price.

Why has this reform been necessary? In short, it's because the way our customers are using the network is changing. And the way we charge has not kept up – it has, in fact, even contributed to electricity prices rising.

We now have a much greater appreciation of how we can structure prices so they better reflect what drives our costs as a network provider and we are reforming our pricing signals to better align with these costs.

This means real savings can now be offered when the network is not being used to its full capacity, and that we are better placed to charge appropriate, ‘cost reflective’ rates during peak period windows in the summer months. It is at these times that the level of demand is more likely to drive future capital investment.

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1. Introduction

1.1 Overview

As a Distribution Network Service Provider (DNSP), Ergon Energy is subject to economic regulation by the Australian Energy Regulator (AER) under the National Electricity Law (the Law) and the National Electricity Rules (NER). Under the Law and NER, the AER is responsible for regulating the revenues Ergon Energy can earn, and the prices that Ergon Energy can charge for certain services provided by means of, or in connection with, our distribution system.

In November 2014, amendments to the NER fundamentally changed the framework in which tariffs for our distribution services are to be developed. Included in these changes were new obligations on DNSPs, including Ergon Energy, to develop prices that better reflect the costs of providing services to customers so they can make informed decisions about how they use electricity.

As part of this new framework, Ergon Energy is required to submit a Tariff Structure Statement (TSS) to the AER setting out our proposed tariff structures for the 2017 to 2020 period and how we have applied the new pricing principles in developing these structures. Once approved, the TSS remains in place for the regulatory control period.

The TSS interfaces with Ergon Energy's Pricing Proposal, which is submitted each year for approval by the AER. Each Pricing Proposal must be consistent with the approved TSS. However, actual rates in the Pricing Proposal are expected to differ from the indicative schedules provided in the TSS. The reasons for these differences will be explained in the relevant Pricing Proposal.

1.1.1 Our network

Ergon Energy supplies electricity across a vast, diverse service area of more than one million square kilometres – across 97% of the state of Queensland.

Around 70% of our electricity network runs through rural Queensland, with large distances between communities. Over two thirds of our customers are located outside Queensland's urban population centres. We service communities from regional Queensland's expanding coastal population centres, to the most remote parts of outback regional Queensland and the Torres Strait.[1]

Ergon Energy's network has been designed, and continues to evolve, to best meet the needs of our customers. This includes responding to the specific needs of our network and customer base, including:

- the significant distances over which assets must be constructed. We have a high proportion of costly sub-transmission assets, compared to our urban counterparts, and one of the largest limited capacity, radial Single Wire Earth Return networks in the world
- the volatile and often harsh climatic environment, including exposure to extreme weather events, which requires us to maintain a significant emergency response capability. In some areas we have seasonal access only due to very significant levels of rainfall.

[1] Ergon Energy supplies communities isolated from the main grid, in western Queensland, the Gulf of Carpentaria, Cape York, various Torres Strait islands, and Palm Island. The pricing arrangements for these customers do not form part of our TSS.

Figure 1: Ergon Energy's service area

With only 7% of all customers across the National Electricity Market (NEM), but covering 44% of the total geographic area, the unique nature of Ergon Energy's network makes the cost of providing services in our network area high, compared to the average network service provider.

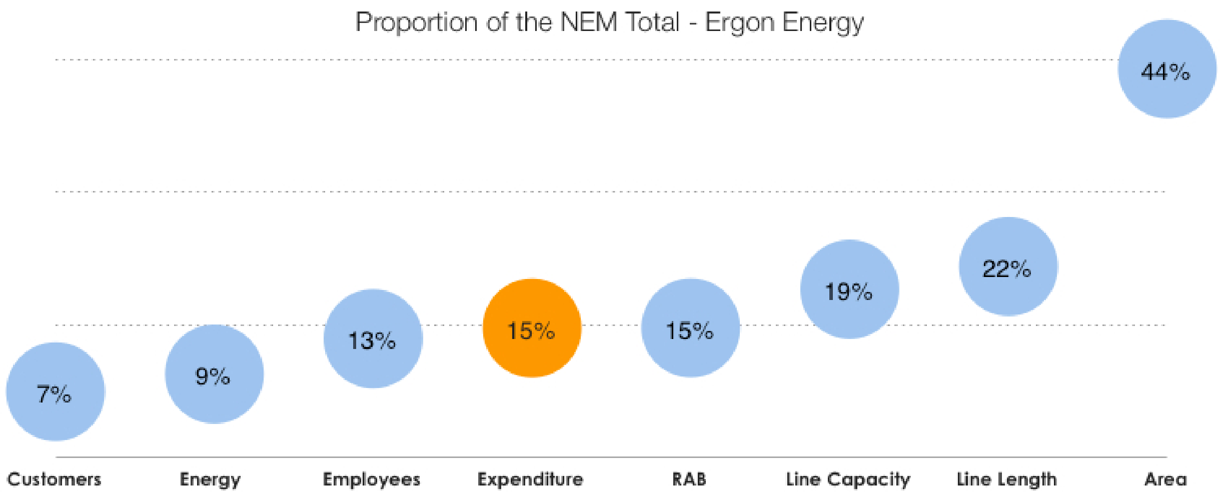

Figure 2: Ergon Energy elements as a proportion of the NEM

1.1.2 Our customers

Our pricing arrangements reflect a complex mixture of different customer types across a multitude of pricing zones. Ergon Energy provides electricity to a population of 1.5 million people – through over 730,000 customer connections:[2]

- Around 725,000 of our customers use less than 100 MWh of electricity a year – of these, 86% are residential customers and 14% are small to medium businesses.
- Our remaining customers are regional Queensland's largest commercial and industrial operations.
    - We have around 8,000 large business customers, using between 100 MWh and 4 GWh a year, operating throughout regional Queensland.
    - The next largest group are the 200-odd customers using over 4 GWh of electricity a year – requiring an 'extra-large' level of network capacity and in many cases a dedicated connection.
    - Our largest energy users, using over 40 GWh a year, are the extra-large coal-mining related operations linked to the Bowen, Surat and Galilee basins. Although only a small number of customers, they make up around 30% of the total energy load on Ergon Energy's network.

[2] As at 30 June 2015.

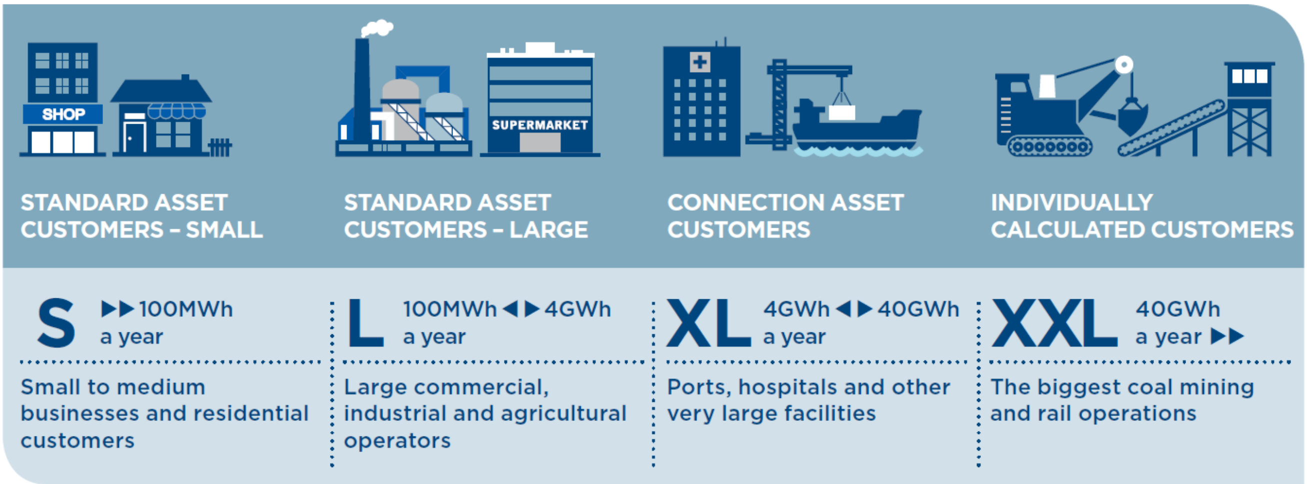

Figure 3: Our customer user groups based on electricity use

1.2 Purpose

This supporting document should be read in conjunction with our Revised Tariff Structure Statement 2017 to 2020 (TSS) which provides detailed information on our network tariff structures and charges for the 2017 to 2020 period, and how we comply with the NER and pricing principles.

This document sets out our approach to stakeholder engagement and outlines further reasons for our approach to pricing and compliance with the pricing principles. It also provides an overview of our TSS, summarises changes between our initial and revised TSS and addresses areas the AER has sought additional information on, in its draft decision on our TSS proposal.

It is structured as follows:

Section	Description
Part 1	• Sets out our approach to network tariffs and stakeholder engagement • Links to our stakeholder engagement overview, on how we have engaged with customers and retailers, including activity since submission of our initial TSS on 27 November 2015
Part 2	• Provides further background on network tariffs and retail tariffs to assist understanding of concepts discussed in the TSS • Provides a useful overview of our TSS
Part 3	Contains additional pricing information and supporting appendices, including: • Our stakeholder engagement overview • Long run marginal costs for Standard Control Services • Excess kVAr Development for ICCs and CACs • Response to AER draft decision • Changes between our initial revised TSS

Part 1 – Our approach to network tariffs and stakeholder engagement

2. Our approach to network tariffs and stakeholder engagement

2.1 Our approach to network tariffs

2.1.1 New regulatory requirements

The Australian Energy Market Commission's (AEMC) 2012 Power of Choice Review focused on the need to increase the economic integrity of signals faced by end-use electricity customers and to increase the scope for them to respond to these enhanced signals. Policy-makers took the view that if retail customers faced tariffs that better reflected the costs of meeting demand, they would have incentives to change their behaviour in ways that could reduce overall system costs.

Changes to the NER followed the Power of Choice Review. In addition to requirements regarding the process for developing a TSS, the NER was amended to expand upon the principles that Ergon Energy must address when establishing prices.

2.1.2 Our network tariff reform journey

Our journey of network tariff reform, which commenced in 2012-13, predates changes to the NER. Nevertheless, the outcomes of our reform program closely align with the changing direction in the NER. Very early on, we saw the necessity to change our pricing arrangements, given the unique nature of our network:

> *To the extent that network charges have not been reflective of costs to date, and customers have responded to those tariffs, customer consumption decisions are likely to have moved away from the economically optimal. This in turn impacts on the load shape presented to the network, capacity requirements of the network, the overall distribution cost base and customer affordability.*[3]

Our journey involved seeking customer and stakeholder input to assist us clearly map out a future pathway for network tariffs that:

- is transparent and sustainable
- provides guidance for future decision making for customers and other stakeholders.

Our objective was to ensure we could continue to meet everyone's needs into the future for the best possible price and to deliver fairer, more equitable pricing signals. To do this, we developed specific reform pathways for each of our customer groups, with the first steps of reform undertaken in July 2014. A number of guiding themes aided our consideration and assessment of the options available to us.

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[3] Ergon Energy (2013), *Network Tariff Strategy Review Consultation Paper*, June 2013, p14.

Our approach has been to move gradually, and transparently, toward more efficient pricing to best manage any customer impacts and implementation issues. We were working hard to ensure our network could meet the changing needs of our customers, but our network charges had not kept pace with these changes, contributing to rising electricity prices.

We were also driving hard to reduce our costs as a business and were confident we would be able to deliver the savings needed to provide an ideal environment for tariff reform. This early start has allowed us to develop a network tariff strategy, with a transparent reform pathway which is managing the impact on individual customers.

As we have already noted, affordability of our network services for customers is a key driver of our tariff reform agenda. Previous research for Ergon Energy found that the impact of increasing uncoordinated solar photovoltaic (PV) penetration and continuation of 'legacy' tariff arrangements may result in customers paying $1 billion more than necessary in the future.[4]

The tariff themes guiding our reforms and the foundation for tariffs in 2017-20 include:

- reducing our over-reliance on volume (kWh) charges
- implementing time-of-use as a critical dimension of cost reflective tariffs
- aligning demand charges to the incremental network costs associated with the demand or the LRMC
- rebalancing between demand (aligned with Long Run Marginal Cost outcomes) and fixed charges
- using kVA more widely as the unit of measure in our network tariffs.

Legacy pricing structures create the wrong customer response, and this distorted response means that some customers pay more than what they should be for using the network while other customers are paying less. Responding to inefficient price signals increases suboptimal bypass of the centralised energy system. This impacts the network via higher voltage management costs and falling utilisation. The cost to serve customers through the network thereby increases, incentivising more bypass – again, with no corresponding reduction in network prices.

There are implications for both the network and retail businesses, but also the economy as a whole, as the total cost of delivering energy in Ergon Energy's network area becomes less efficient.

Our preferred future is one that provides the right signals to customers so that the choices each customer makes in using the network is reflected in the price they pay (and not in the price other customers pay).

The other important consideration in our approach has been the need to create value in the network for those seeking to adopt new and emerging energy-related technologies. Our reforms allow these innovations to be accommodated where it makes sense, and deliver real value to those investing in their own solutions, like solar and battery storage combinations, without being cross subsidised by other network users. Our approach also supports technologies, like electric vehicles, that could significantly boost the utilisation of the network, which helps reduce the unit cost of supplying electricity for all.

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4 Energeia (2015), *Maximum Demand Tariff Analysis Report*, April 2015.

2.2 Our stakeholder engagement program

Since commencing our engagement process in 2013, Ergon Energy has released six key consultation papers with supporting documentation and held five dedicated consumer advocacy sessions and a series of webinars. Following suggestions from stakeholders, we also developed a short video to assist consumers to understand the reforms. Opportunity to comment was provided on five occasions, resulting in over 80 formal submissions.

Ergon Energy has made efforts to reach our different customer classes and respond to requests for further information.

700+ customers and other stakeholders were invited to open webinars on the reforms.

Over 80 formal submissions were received throughout the process – guiding our thinking.

Our consultation on network tariffs has helped us develop the initial strategy, implement reforms and refine the pathway, and more recently helped us prepare our TSS.

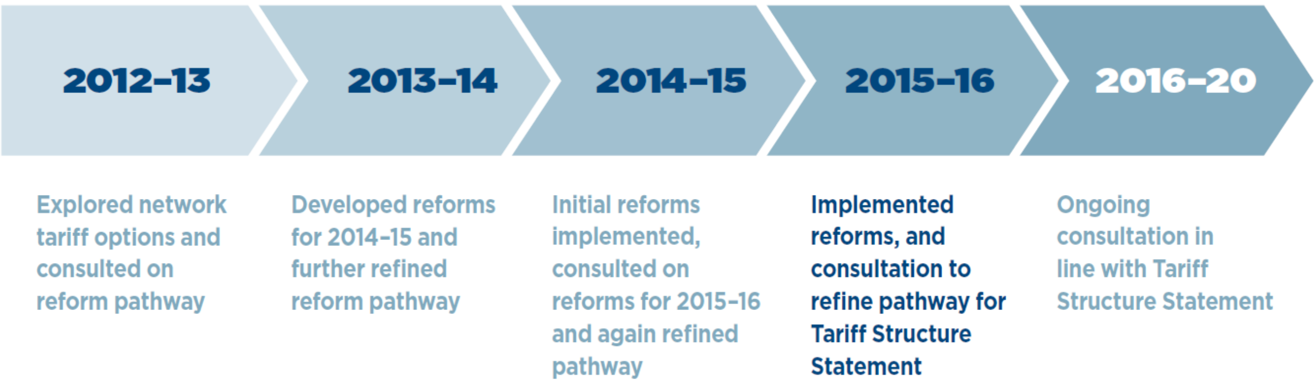

Figure 4: Stakeholder engagement is playing a key role in our journey

The channels used for our engagement included:

- Ergon Energy web pages (www.ergon.com.au/futurenetworktariffs)
- qualitative interviews
- stakeholder sessions
- our Customer Council and other Ergon Energy-led industry forums
- open webinars
- published consultation papers
- Talking Energy (www.ergon.com.au/talkingenergy).

The primary stakeholder groups we engaged included consumer representatives, very large customers, retailers, regional stakeholders and interested customers, and regional Queensland's solar installers/electrical contractors.

2.2.1 What our customers want

The major themes in the responses included:

Over 80% of attendees in our biggest open webinar were looking for us to act, but gradually, to remove the cross subsidies that will grow under existing charging arrangements.

…………………………...………

- *significant concern around the rise in electricity prices in recent years*: this has created a tension, as network prices are a significant component of the bill, between a recognition of the need to remove the cross subsidies in tariffs that exist as early as possible and the need for more time to ensure customers are able to respond to the changes.

  This has led to general support for the voluntary nature of the new tariff options now being made available and the staged introduction of other reforms.
- *desire for a greater understanding around the customer impacts/opportunities in the new voluntary demand-based tariffs*: this is seen as key to being able to educate customers appropriately and, ultimately, for them to be confident in choosing to adopt the new tariffs. It will also be important to ensuring there are adequate protections for customers.
- *concern around the ability of some customers to respond to the price signals and control the timing of their demand*: while these concerns do exist, there is a growing understanding of how the path we have been progressing along can support the best price outcome for all, over the longer term.

Further information on our network tariff reform journey and the consultation we have undertaken to inform the development of this TSS is available in Appendix A. The documentation created throughout this process is also available on our website at: www.ergon.com.au/futurenetworktariffs.

2.3 Stakeholder engagement between initial and revised TSS

Since finalisation of our TSS for submission on 27 November 2015 we have maintained engagement with customers and stakeholders on our network tariffs.

Webinars

We have continued to prefer webinars as the platform to efficiently support participation by stakeholders across Queensland and interstate. Webinars are also well suited for recording and making available on our internet site.

The following webinars have been held, commencing 26 November 2015:

- *Webinar: An Update: Ergon Energy's Network Tariff Reforms – 26 November 2015*. A preview of our Tariff Structure Statement, including the refinements planned for 2016-17. Recorded and posted to the web, questions responded to during the webinar and followed up.
- *Webinar: An Update: Ergon Energy's Network Tariff Reforms – 1 April 2016*. Held prior to the AER consultation forum in Brisbane linked to AER Issues paper. Recorded and posted to the web, questions responded to during the webinar and followed up.
- 3 Webinars linked to our 2016-17 Pricing Proposal submission in the context of alignment with the TSS for 2018-2020:
  - *2016-17 Pricing Proposal Briefing for customers using less than 100MWh a year - (Standard Asset Customers – Small) – 11 May 2016*
  - *2016-17 Pricing Proposal Briefing for customers using more than 100MWh a year -*

(Standard Asset Customers – Large) - Wednesday, 11 May 2016

 - *2016-17 Pricing Proposal Briefing for customers using more than 4GWh a year - Connection Asset Customers (>4GWh pa or >1,500kVA), Individually Calculated Customers (>40GWh pa) -Thursday, 12 May 2016.*

- Webinar: *An Update: Ergon Energy's Network Tariff Structure Statement – 14 September 2016.* Held to update on TSS draft decision, our important take-outs, how we are planning to respond, TSS clarifications and encouraging stakeholders to respond. Recorded and posted to the web, questions responded to during the webinar

2016-17 Pricing Proposal activity

Following approval of the 2016-17 Pricing Proposal we wrote to all our ICC and CAC customers individually and in particular advised CAC customers of the change with respect to commencement date for the excess kVAr charge.

On 30 June 2016 we published six updated brochures:

- Understanding Network Tariffs –for customer using less than 100MWh
- Understanding Network Tariffs –for customer using more than 100MWH
- Understanding Network Tariffs –for customer using more than 4 GWh
- Understanding Network Tariffs –for customer using more than 40 GWh
- General Guide To Measuring Electricity Demand
- Understanding kVA and Excess kVAr Charges for Major Customers (CAC & ICC)

These brochures were used to support customers and stakeholders in understanding the 2016-17 changes to the tariffs that will flow through into the TSS and also to reinforce that the change that CACs were expecting to kVAr had been deferred a year at AER request.

Other initiatives

Also through our Customer Council and Agricultural Forum we have kept stakeholders up to date with TSS activity.

We see all of the above activity as part of customer support and education. In the draft decision the AER noted customers will require ongoing education and support with respect to new cost reflective tariffs.

Our current initiative here, outside of our direct engagement and webinar program, is the deployment of a real life tariff trial – in partnership with Ergon Energy Retail – to enable customers to gain experience and understanding of the new cost reflective tariffs. This is vital to remove some of the uncertainty.

The internal part of the trial is well underway and we have 88 Ergon Energy employee sites where smart meters have been deployed and a structured paper trial has commenced based on the residential retail tariff. This includes nine trailblazer sites, which have already provided valuable learning. We are also working on an initiative to assist customers who don't have a smart meter to assess their demand based on their current energy usage data. This in turn would allow customers to understand the STOUD tariffs – and to assess the potential benefit for them.

We have undergone a major change to our billing systems over the last few months, and are still working through that. Once we have that resolved we will look again for an appropriate start date to take the tariff trial to external customers for both Tariff 14 and 24.

This is all being supported, of course, by the QCA creating retail tariffs to reflect the structure of our new seasonal time of use demand network tariffs.

Part 2 – Understanding network tariffs and our Tariff Structure Statement

3. Understanding network tariffs

3.1 Your electricity bill

A customer's retail electricity bill has a number of components (see Figure 5).

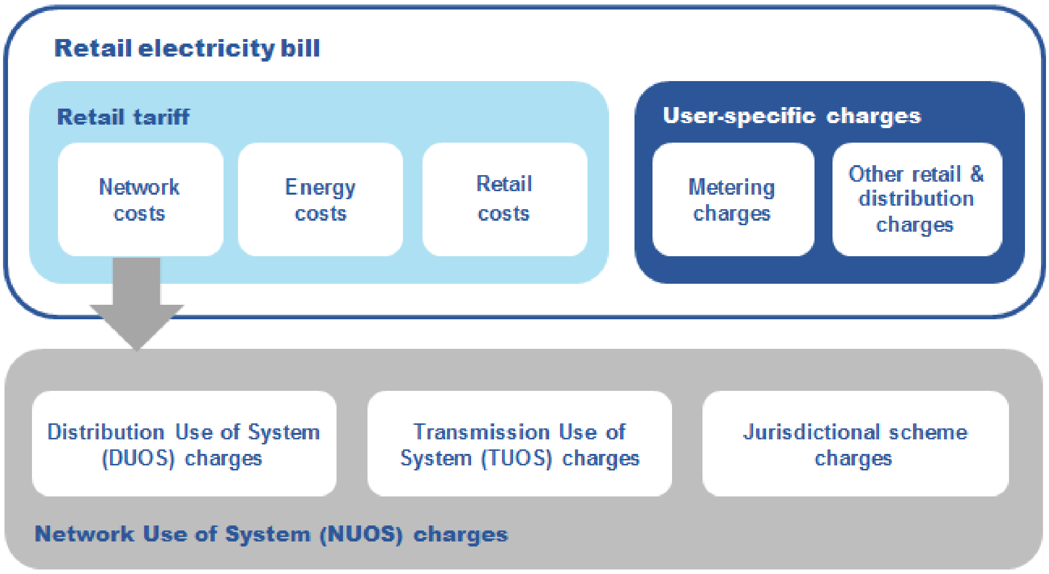

Figure 5: Components of a customer's retail electricity bill

As illustrated by the above diagram, the bill a customer receives from retailers incorporates our network charges, as well their energy and retail costs. The charges a retailer receives from us (the NUOS charges) are further broken down into:

- what Ergon Energy charges for the use of our network (DUOS charges)
- what Powerlink charges Ergon Energy for TUOS (Powerlink's costs of transmitting energy from generators to our network) plus other transmission-related charges
- payments made to eligible customers under the Queensland Government's Solar Bonus Scheme and the energy industry levy which Ergon Energy is required to recover (jurisdictional scheme charges).

In summary, Ergon Energy's NUOS charges include the costs we charge for the use of the network (DUOS) but also include the costs we pass on to customers that are outside our control (TUOS and jurisdictional scheme charges).

We also determine charges for ACS (see Part 3 of this TSS). These charges do not form part of the NUOS charges billed to retailers. Rather, they are separately levied on the customer or retailer requesting the service. The most common user-specific charge found on a customer's retail bill relates to metering.

3.1.1 The impact of network tariffs on a retail bill

Each year the Queensland Competition Authority (QCA), under a delegation from the Queensland Government, sets regulated retail electricity prices or 'Notified Prices' based on its latest forecasts of providing electricity services. To calculate each regulated retail tariff (apart from historical transitional tariffs), the QCA uses a 'Network plus Retail' cost build-up approach. The underlying network cost component may be based on our network tariffs and/or rates, or those of Energex Limited (Energex).

For the majority of our customers their retail bill is subsidised by the Queensland Government in line with the Uniform Tariff Policy. This policy, and the associated Community Service Obligation payment made by the government to our retailer (Ergon Energy Queensland Pty Ltd), ensures that Queenslanders generally have access to the same cost of electricity, regardless of where they live.

For residential and small to medium business customers, who use less than 100 MWh of electricity a year, this means our network tariff – the Inclining Block Tariff (IBT) – and our rates for all tariff structures are not used as the basis for the QCA's regulated retail tariffs. These tariffs, which are accessed by the majority of customers in regional Queensland, are largely based on Energex's network charges for south east Queensland. However, our reforms are helping to introduce greater choice for this group.

For businesses using more than 100 MWh of electricity a year, Ergon Energy's network tariffs are typically passed on through the QCA's Notified Prices. However, there are some exceptions.

The impact of Ergon Energy's network tariffs also depends on whether a customer is on a regulated retail tariff(s) or on a contract with a competitive retailer. For customers on a 'market contract', their retailer will determine if or how our rates or tariff structures are passed through.

3.2 Key concepts in tariff design

There are a number of pricing concepts discussed in the TSS. To assist understanding, we have explained these concepts below.

3.2.1 Tariff classes

We have a wide diversity of customers, in terms of their size, location, and usage patterns. We group our customers according to these characteristics. Tariff classes therefore refer to a group of customers with similar characteristics. Ergon Energy has 18 tariff classes for SCS customers. These tariff classes are detailed in Section 5.1 of our TSS.

3.2.2 Tariff structures, charges and charging parameters

A tariff represents the combination of charges that Ergon Energy applies to a customer (through their retailer) in order to recover network costs (or NUOS). Within each tariff class a number of tariffs can be offered.

Tariffs have three key defining characteristics:

- the charge (can also be called 'charging component', 'tariff component' or 'tariff element')
- the parameters of the charge (specific characteristics that relate to the charge that influence how it is calculated)
- the rate applied to each charge.

Each tariff has at least one charge, but usually has more than one. Ergon Energy uses six broad types of charges and charging parameters for our SCS as shown in Table 1.

Table 1: Types of charges and charging parameters

Charge	Charging Parameter
Fixed charge	Represented as a rate per day. Structures for most tariffs include a fixed charge.
Volume charge	Represented as a rate per kWh. Structures for most tariffs include a volume charge. However, different parameters apply to this charge for different tariffs. These are explained in Chapter 5 of our TSS. Within a tariff structure, volume charge rates can be flat or be applied to different blocks (based on consumption) or times (peak and off-peak).
Demand charge	Represented as either a rate per kW or a rate per kVA. Most tariffs include a demand charge. Different parameters apply to this charge for different tariffs. These are explained in Chapter 5 of our TSS. Within a tariff structure demand charge rates can be: • applied year round or seasonally (with different peak and off-peak rates) • calculated based on: ○ a single period in the month ○ the maximum demand within a peak demand window ○ an average of demands within a demand window. Some tariff structures include a floor (the demand charge must include at least the rate times 'X' demand) or a threshold (the demand charge is only calculated for demands recorded above a particular level).
Capacity charge	Represented as a rate per kVA. Sections 5.6 and 5.7 of our TSS outline the application of capacity charges for our ICC and CAC tariffs.
Excess reactive power (kVAr) charges	Represented as a rate per excess kVAr. Sections 5.6 and 5.7 of our TSS outline the application of excess reactive power charges for our ICC and CAC tariffs.
Connection unit charges	Represented as a rate per connection unit per day. Section 5.6 of our TSS outlines the application of connection unit charges for our CAC tariffs.

3.2.3 Our pricing zones

Unlike most other DNSPs, Ergon Energy develops prices for three different pricing zones. These are based on geographic areas of the network where costs are assessed to be broadly similar. These pricing zones are:[5]

- **East Zone** – those areas where the network users are supplied from the distribution system connected to the national grid and have a relatively low distribution cost to supply
- **West Zone** – those areas outside the East Zone and connected to the national grid, which have a significantly higher distribution cost to supply compared to the East Zone
- **Mount Isa Zone** – broadly defined as those areas supplied from the isolated Mount Isa system. This zone is not connected to the national grid and, as such, would normally be excluded from the application of the NER. However, under the *Electricity – National Scheme (Queensland) Act 1997*, the Queensland Government has transferred responsibility for the economic regulation of the Mount Isa–Cloncurry supply network to the AER.

3.2.4 Cost reflective tariffs

'Cost reflective' tariffs are simply charges that are better aligned with the underlying cost of supplying electricity. This means charging appropriately when the level of demand across the network is likely to drive future capital investment – Ergon Energy builds new infrastructure largely in response to demand during summer months.

This is seeing us align the demand-related components of our charges to the incremental costs or the additional future network costs associated with demand in the summer peak window- what is called our Long Run Marginal Costs (LRMC).

In recent times we have reviewed our LRMC in line with changes to the NER by the AEMC.

Our cost reflective tariff options, like our general tariffs, have different rates across our three pricing zones – East, West and Mount Isa. This reflects the different costs of supplying these areas.

However, the Uniform Tariff Policy ensures that Queenslanders generally have access to the same cost of electricity, regardless of where they live, the regulated retail tariffs are largely reflective of the network costs in south-east Queensland.

3.2.5 Mandatory, opt-in and opt-out tariffs

Tariffs can be either 'mandatory' 'opt-out' or 'opt-in' for particular customers. An explanation of each of these is set out below:

- Mandatory tariffs – are the only tariff available for particular customers. For example, unmetered supplies within our network (e.g. public lighting, traffic lights) can only access the unmetered supply network tariff.
- Opt-out tariffs – are assigned to customer's by default, but customers may choose to be re-assigned to a different tariff. For example in 2016-17 residential customers are automatically assigned to our residential inclining block network tariff.
- Opt-in tariffs – are tariffs the customer can choose to be reassigned to. For example residential customers in 2016-17 may choose to be assigned to the seasonal time-of-use energy or seasonal time-of-use demand tariff, instead of the default tariff (inclining block)

An indication of whether tariffs are mandatory, opt-in or opt-out is included in the overview below.

3.3 Ergon Energy suite of network tariffs 2017-2020

The following section provides a useful overview of our network tariffs in the 2017-2020 period as outlined in our TSS. We also publish separate online guides which help our customers understand our network tariffs.

3.3.1 Residential and small to medium business customers (SAC Small)

For our small to medium business and residential customers, who use less than 100MWh of electricity each year, we have a range of network tariffs:

- Inclining Block Tariff (IBT) (*opt-out)*[6]
- Seasonal Time-of-Use Energy (STOUE) (opt-in)
- Seasonal Time-of-Use Demand (STOUD) (opt-in)

Many customers, in addition to the above primary tariffs, enter into arrangement with Ergon Energy whereby some appliances are subject to a secondary "controlled load". Controlled load tariffs allow us to curtail supply to designated circuits at a customer's premises in return for a lower tariff.

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[6] Opt-out and opt-in arrangements for the SAC small group may change in the 2017-2020 period. Our TSS notes that we may move to an opt-out approach to the STOUD for new connections (where the installed meter is capable of applying the tariff) from 1 July 2018.

We have two controlled load tariffs:

- Volume Controlled (opt-in)
- Volume Night Controlled (opt-in)

Our SAC small group also covers unmetered supplies such as public lighting, traffic lights, watchman lights and other types of unmetered public amenities (e.g. illuminated signs, phone boxes and barbeques etc.). Only one type of network tariff is available for this customer group:

- Volume Unmetered (mandatory)

Our SAC small tariff structures are explained in further detail in our TSS.

What to expect in the 2017 to 2020 period

The primary tariffs that customers in this group automatically default to are Inclining Block Tariffs (business and residential). While not reflected directly in the regulated retail tariffs that Ergon Energy Retail offers customers, Ergon Energy Network will continue to use these tariffs throughout the 2017 to 2020 period.

Moving forward, to be more cost reflective, the tariffs for this group of customers need to have a bigger focus on the amount of electricity used at specific times of the day, during the busiest or peak times for the network, rather than how much energy is used over the billing period.

Our demand-based tariffs (STOUD) are our preferred options for the future. Since being introduced we have been listening to stakeholders, and working hard to refine these tariffs. This has seen us simplify the way the tariffs are calculated for 2016-17. The charges in the tariffs will now be calculated in the same way for the summer and non-summer months.

It will now be calculated throughout the year using an average of the demand a customer places on the network for the month in the relevant daily demand window. Our reforms are also continuing to gradually increase the cost reflectivity of the summer charge.

At the moment a customer (via their retailer) must request a tariff change if they wish to adopt this tariff. This is subject to the provision of compliant metering. Changes to the NER may affect obligations surrounding the ownership of metering services and the availability of Type 4 metering. Depending on the outcome of these changes we may seek to apply the STOUD to all new premises connections (with installed metering capable of applying the tariff) from 1 July 2018. Customers will still have the option not to have the STOUD applied to their premises and choose the alternative STOUE or IBT that we offer.

Reforms are also being made to our secondary controlled load tariffs. These are ideal for connecting to hot water systems and other load that can be switched off at different times during the day to help us manage the load on the network without too much inconvenience to the customer.

We currently have two of these secondary tariffs. Our Volume Night Controlled tariff, which supports the Notified Retail Tariff 31 Night rate (super economy), and our Volume Controlled tariff, which supports the Notified Retail Tariff 33 Controlled supply (economy). The first provides the greatest savings with supply made available for at least 8 hours a day, for the second this is extended to 18 hours a day. Our reforms are rebalancing the rates for these tariffs to better reflect our improved understanding of the cost associated with additional demand on the network during peak periods.

No changes are expected to our tariffs for unmetered supply in the 2017-2020 period.

3.3.2 Commercial industrial and rural industry customers (SAC Large)

These are our commercial, industrial and rural industry customers who use between 100MWh and 4GWh of electricity a year – they are located throughout the distribution network. Our tariffs for this group include:

- Demand High Voltage[7] (opt-out)
- Demand Large (opt-out)
- Demand Medium (opt-out)
- Demand Small (opt-out)
- STOUD (opt-in)[8]

Further detail on our SAC Large tariff structures is set out in our TSS.

What to expect in the 2017 to 2020 period

The new seasonal time-of-use demand tariff, introduced for this group in July 2015, has been well received and taken up by customers. This option has come about from our work to better understand our cost drivers and make our tariffs more cost reflective. Unlike the other demand tariffs available for this group, this tariff recognises the peak demand window that occurs in the summer months.

Given the general anytime demand tariffs for SAC Large customers are usually self-selecting, our preference would be, from July 2017, for new premises and customers moving into existing premises (with required metering) to be subject to the STOUD (with the option of choosing the general anytime demand tariffs if desired).

For this group we have also reviewed the introduction of kVA tariffs. While we consider that benefits warrant extending the changes already made for our largest customers over the last two years, this will not be progressed for SAC Large customers before 2020. We will engage on this again at a later stage as we begin to develop our position on tariffs for beyond 2020.

We are also considering establishing more cost reflective charging arrangement for SAC Large customers requesting an alternate supply (more than one connection to the network). However we will not progress any changes in the 2017-20 period. We will look to undertake further analysis and consultation and establish any new tariffs (if required) after 2020.

3.3.3 Large commercial and industrial customers (CAC)

These customers typically consume between 4GWh and 40GWh a year – they are regional Queensland's extra-large industrial mining, fabrication and farming operations, sugar mills, large shopping centres, hospitals, universities, correctional centres, defence force bases and large pumping stations. Our tariffs for this group include:

[7] Demand High Voltage tariff is being phased out.
[8] Opt-in and opt-out arrangements may change for the SAC Large group in the 2017-2020 period

- CAC 22/11 kV Line (opt-out)
- CAC 22/11 kV Bus (opt-out)
- CAC 33kV (opt-out)
- CAC 66kV (opt-out)
- STOUD CAC 22/11 kV Line (opt-in)
- STOUD CAC 22/11 kV Bus (opt-in)
- STOUD CAC Higher Voltage (66/33 kV) (opt-in)

Our CAC tariff structures are explained in further detail in our TSS.

What to expect in the 2017 to 2020 period

While reforms for this group have lagged the other groups, they are now on a similar reform pathway as our largest customers. The first step, in July 2015, was to standardise the tariffs available with a connection unit charge based on the assets dedicated to them.

The other move was to use kVA (kilovolt amperes) as the basic unit for charging demand and capacity charges. The next step here, in 2017-18[9], is the introduction of an excess reactive power or kVAr (kilovolt amperes reactive) charge. This encourages customers to improve their sites' power factor and reduce the network capacity they require.

In 2015-16 we also introduced a seasonal, time-of-use demand tariff for this group. After further analysis, a number of improvements were made to the tariff in 2016-17. In summary, the summer peak demand charge is no longer based on the greater of the authorised demand and monthly maximum demand during the peak period, and the capacity charge is no longer charged on the greater of a monthly floor and the monthly maximum demand during the non-summer months.

These changes will make it more attractive for customers and provide a greater incentive for them to respond to the pricing signal in the summer peak demand window.

Similar to SAC Large customers, we are also considering establishing more cost reflective charging arrangement for CACs requesting an alternate supply (more than one connection to the network). However we will not progress any changes in the 2017-20 period. We will look to undertake further analysis and consultation and establish any new tariffs (if required) after 2020.

3.3.4 Individually Calculated Customers (ICC)

Our largest customers are the state's major coal mining customers, as well as customers involved in other types of mining, transport (rail) and pumping. These customers use more than 40GWh of electricity each year.

The tariffs for these customers are calculated on an individual basis to reflect the specific site's load requirement. ICC tariffs are also considered mandatory (only tariffs available for these customers)

Further detail on our ICC tariff structures is set out in our TSS.

What to expect in the 2017 to 2020 period

In 2014, Ergon Energy introduced kVA charging for this user group. We then introduced, in 2015, an additional charge against the excess reactive power or kVAr drawn from the network that

[9] Subject to approval by the AER through the 2017-18 Pricing Proposal

exceeds the quantity that the customer would draw operating at their authorised demand with a compliant power factor.

Due to the demand on the network that comes from these customers, their premises' power factor is especially important, as a distribution system must be designed to supply the actual power required. A low power factor means the actual power delivered will be unnecessarily high.

As the reforms to date have brought these tariffs in line with the principles of cost reflective pricing, we have not identified further reforms for 2017-20. We do, however, see an opportunity in the future to improve the alignment between the signal a customer receives for exceeding their authorised demand and the LRMC. This will require further customer engagement, with any changes (if required) occurring after 2020.

3.3.5 Embedded Generators (EG)

Embedded Generators are network users who export into our distribution system. This customer grouping is designed to cover larger embedded generators, and does not include small scale generation facilities captured under Australian Standard (AS) 4777.1 – 2005 (for example a small scale rooftop PV system).

The tariffs for embedded generators are calculated on an individual basis. EG tariffs are also considered mandatory (only tariffs available)

Our EG tariff structures are explained in further detail in our TSS.

What to expect in the 2017 to 2020 period

Reforms for this group have lagged the other groups, with tariffs remaining largely unchanged up until 2016. In 2016, we made some improvements to charging arrangements for those EGs who are also an ICC or CAC for their load. To recognise the contribution the generator may make to the kVA and kVAR demand components, when charging for the (ICC or CAC) load we now set the export kVAR to zero in any interval when kW are imported into our distribution network.

Ergon Energy is also starting to see an increase in the number of embedded generators seeking a connection to our network. If this trend continues, we do see an opportunity to standardise the rates for embedded generators, instead of continuing to price these individually.

Our preference would be to move to standardised pricing before 2020, if the number of embedded generator connections grows significantly over the 2017-20 period.

3.4 Network tariff levels

In setting the level (or price) of network tariffs, Ergon Energy must comply with a number of distribution pricing principles. For example, the rules require Ergon Energy to:

- set each tariff based on the long run marginal cost (LRMC) of providing network services to consumers assigned to the tariff
- adjust LRMC based prices to recover total efficient costs in a way that minimises distortions to the efficient usage decisions of consumers
- consider the impact on consumers of changes to tariffs between regulatory years, and adjust prices to the extent necessary to meet consumer impact principles and enable a smooth transition to cost reflective tariffs

Expected revenue recovered from our tariffs must also:

- for each tariff class, be between the stand alone costs of serving those customers and the avoidable costs of not service those customers
- for each tariff, reflect our efficient costs of serving customers assigned to that tariff
- permit Ergon Energy to recover the expected revenue in accordance with the AER's Distribution Determination.

More detailed information on our compliance with the distribution pricing principles is set out in our TSS.

3.5 Alternative Control Services

This *Supporting Information – Revised TSS* focuses on explaining our TSS with respect to our Standard Control Services (the revenue for which is recovered through network tariffs).

Our TSS also outlines the tariff structures and compliance with the distribution pricing principles for our Alternative Control Services (services with attract separate user-specific charges). The tariff structures and tariff levels for Alternative Control Services are almost entirely determined through the AER's distribution determination and annual Pricing Proposal.

For further information on these services, please refer to our TSS. We also publish a Price List for Alternative Control Services which provides a description of our Alternative Control Services and their prices.

Part 3 – Additional pricing information and appendices

Appendix A Our stakeholder engagement overview

1 Listening to our customers

Ergon Energy would like to acknowledge the time and resources invested by a diverse range of customers and other stakeholders while participating in the development of our network tariff strategy.

Stakeholder contribution to the discussions has been instrumental in forming our views on the appropriate path forward, with specific input incorporated into the tariff development process and ultimately the tariff structures detailed in our Tariff Structure Statement (TSS). Better outcomes have been achieved as a result of these contributions.

2 Our engagement approach

When we first began to consider our longer term network tariff strategy, we recognised the potential for impacting our customers and other stakeholders, and acknowledged the important contribution that their insights could make towards the development of our reform pathway.
In recent times, in particular, the peak bodies and other advocacy groups who represent our customers have gained a greater capacity to represent their constituents around the detail in our proposals (thanks to our engagement programs and that undertaken by other providers, industry regulators and government). This has improved the effectiveness of our engagement on the challenges in front of us as an essential service provider and, more generally, as an industry.

With this in mind we endeavoured to make the matters under consideration across our reform agenda as transparent as possible and make any information we had accessible to potentially impacted customer segments.

We actively sought stakeholder feedback so that stakeholder concerns could be considered in our decisions – and we published these responses online.

The primary stakeholder groups we engaged included consumer representatives, very large customers, retailers, regional stakeholders and interested customers, and regional Queensland's solar installers/electrical contractors. These groups provided representation across our key customer segments, from our residential and small to medium business customers to our very large business customers and across our large service area.

700+ customers and other stakeholders were invited to webinars on the reforms, including our biggest business customers and the retailers operating in regional Queensland.

Over 80 formal submissions were received throughout the process – guiding our thinking – following the release of consultation papers.

Our stakeholder mapping also recognised other external stakeholders, such as regulatory bodies and government, most notably the Queensland Competition Authority (QCA).

Since commencing our network tariff strategy engagement process in 2013, Ergon Energy has released six key consultation papers with supporting documentation, held five dedicated consumer representative sessions and a series of open webinars. Following suggestions from stakeholders we also developed a short video to assist customers to understand the drivers for the reforms. This material has all been made available online.

The opportunity to provide formal feedback resulted in us receiving over 80 written submissions. Our pricing team has also responded to requests for further information as required.

The channels used for our engagement included:

- Ergon Energy web pages (www.ergon.com.au/futurenetworktariffs)
- qualitative interviews
- stakeholder sessions
- our Customer Council and other Ergon Energy-led industry forums
- open webinars
- published consultation papers
- Talking Energy (www.ergon.com.au/talkingenergy).

3 The journey and engagement inputs

Stakeholder engagement along the network tariff reform journey has helped develop the initial strategy, implement key reforms in 2014 and 2015 and refine the pathway as we moved forward. Most recently, our engagement assisted with the preparation of our TSS.

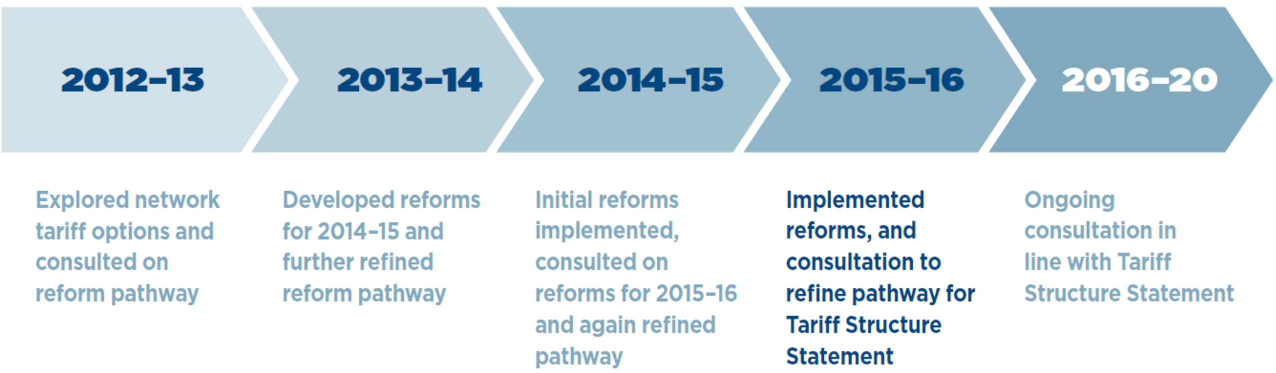

Figure 1: The network tariff reform journey and consultation steps

2012-13

Our first phase of engagement commenced in 2012-13 with targeted, qualitative customer interviews undertaken by our external consultants, Ernst & Young, who were commissioned to develop our tariff reform options and possible reform pathways.

2013-14

We then launched a public consultation process, with two phases of engagement undertaken throughout 2013-14, to inform both the changes to be implemented in July 2014 and our longer term tariff strategy development and reform pathway. The opportunity to provide feedback on the changes was promoted using press advertising and other channels.

We also facilitated direct engagement processes (letters, emails and one-on-one) with potentially impacted large customers, as well as other stakeholders, including retailers and community leaders. This led to 46 stakeholder submissions in total.

2014-15

Next, in late 2014, we commenced an engagement process on proposed changes to our 2015-16 tariffs with the publication of our consultation paper, *Future Network Tariffs 2015-16*.

At this time we also published and distributed a brochure, *Electricity Demand Charges for Business Customers*, to help explain the changes underway to our demand charging arrangements for business customers who use more than 100 MWh of electricity a year.

The opportunity to provide feedback on the changes was again promoted using press advertising and direct engagement.

We also held two face-to-face consumer representative group meetings to assist stakeholders in understanding the changes:

- The first session, in December 2014, covered why the reforms were being undertaken and a high level exploration of the journey to date.
- The second session, in February 2015, detailed the changes proposed for each customer group, and expanded on the case for changing to demand-based tariffs for all customers. External energy research and advisory specialists, Energeia, presented the modelling they had undertaken to estimate the cost to customers as a result of inaction.

In addition to the feedback received through these sessions and over 20 individual large customer enquiries, 16 formal stakeholder submissions were received on our first consultation paper.

In March 2015, we then went back to stakeholders to consult on two further matters:

- The first matter related to changes to our peak energy and demand rates following a review of our Long Run Marginal Cost (LRMC) calculation in response to the Australian Energy Market Commission’s (AEMC) new network pricing rules. This was covered in the supplementary consultation paper, *Aligning Network Charges to the Cost of Peak Demand*. This paper was accompanied by two supporting documents:
  - *Long Run Marginal Cost Considerations in Developing Network Tariffs*
  - *Estimating the Average Incremental Cost of Ergon Energy's Distribution Network*.
- The second matter was our proposal to bring forward the introduction of a voluntary Seasonal Time-of-Use Demand tariff for residential and small to medium business customers, to July 2015. This was covered in the supplementary consultation paper, *The Case for Demand Based Tariffs*.

We directly engaged with large customers on these matters and also held a third face-to-face consumer advocate group session in March 2015, focusing on the changes affecting our residential and small to medium business customers, and the potential opportunities associated with the Seasonal Time-of-Use Demand tariff.

In order to ensure we consulted with as wide a group of stakeholders as possible from across our entire network area we also undertook a number of webinar presentations.

Initially, two webinars were held in March 2015 to provide an opportunity for different customer groups to learn more about our proposed network tariff reforms for 2015-16 and beyond. Around 700 invitations were sent to key stakeholders. The first webinar focused on large customers using more than 4 GWh of electricity per year. The second addressed smaller customers using less than 4 GWh of electricity per year.

Table 1: Webinar statistics

	Customers less than 4 GWh p.a.	Customers more than 4 GWh p.a.
Total attendees	**74**	**49**
Invited to attend	Approximately 450	Approximately 250
Clicked registration link	197	134

Supplementary webinar recordings and Questions and Answers were also published on-line to provide stakeholders with further information, especially on the calculation of the Seasonal Time-of-Use Demand tariff for the different business customer classes.

In addition to consulting with the Energy Retailer’s Association of Australia and engagement with individual retailers, we hosted a retailer-specific webinar in April 2015, which covered the proposed network tariff reforms including the potential billing implications.

This phase of our engagement led to a further eight stakeholder submissions.

During the timeframe of the Ergon Energy stakeholder consultations, the QCA was also undertaking regional workshops on regulated retail electricity prices. We reviewed the public submissions made to the QCA relating to the draft determination to ensure any issues raised in the context of the QCA’s draft determination were incorporated into our considerations.

In response to stakeholder feedback, we also developed two tariff calculators, one for business customers and the other for residential customers, so interested customers could estimate for themselves the impact on their bills of adopting the Seasonal Time-of-Use Demand tariff. This now has to be redeveloped to reflect the regulated retail tariffs that have since been launched.

To assist targeted customer engagement, mini tariff guides of the changes, including one for each customer group were also published on our website.

The stakeholder engagement process undertaken by both ourselves and the QCA supported the launch of a suite of new regulated retail tariffs which:

- were demand-based
- were seasonal
- reflected the tariff structure and charging parameters of the underlying Ergon Energy network tariff.

The latter point was an important development for Ergon Energy and our customers. Previously regulated retail tariffs in regional Queensland were based on the structure and charging parameters of the Energex network tariff. This more recent change improves the economic signals for customers on regulated retail tariffs in our network area while still affording those customers subsidised tariffs consistent with the Queensland Government’s Uniform Tariff Policy.

2015-16

As we moved into 2015-16 we were engaging firstly on the tariff reforms achieved to date and the network tariff strategy development undertaken during 2014-15 (and how we had responded to stakeholder concerns). We also, at that point, provided an opportunity for our customers and other stakeholders to provide further input as we moved to draft our TSS.

This commenced with the release of the Consultation Paper, *Our Network Tariff Reform Report*, in June 2015. Then, in July 2015, we engaged through another stakeholder session, and subsequently through one-on-one engagement with consumer representatives.

This engagement focused on the new rules in relation to the TSS and basing prices on LRMC. We also considered customer impacts in the setting of prices/tariff structures, as well as any feedback on the possible approaches to the implementation of the demand-based tariff.

In October 2015, we also held a general stakeholder information session on our demand forecasts.

Table 2: Engagement activity summary

Topic	Engagement activity
2013-14 for: **Initial strategy and 2014-15 reforms**	Phase 1 – Network Tariff Strategy Review Consultation Paper July 2013 (37 submissions received)
	Phase 2 – Tariff Implementation Report for 2014-15 (with customer impact analysis) November 2013 (9 submissions received)
2014-15 for: **2014-15 reforms**	Future Network Tariffs (next steps in 2015-16) Consultation Paper December 2014 (16 submissions received)
	Consumer Representative Stakeholder Session December 2014
	Consumer Advocate Stakeholder Session February 2015
	Cairns Stakeholder Session Metering February 2015
	Supplementary Consultation Papers: Aligning Network Charges to Cost of Peak Demand/The Case for Demand Based Tariffs March 2015 (8 submissions received)
	Consumer Advocate Stakeholder Session March 2015
	Information webinars (four webinars) March/April 2015 (over 130 participants)
2015-16 for: **2015-16 reforms/TSS**	Our Network Tariff Reform Report Consultation Paper (2015-16 Reforms/Tariff Structure Statement) June 2015 (10 submissions received)
	Consumer Advocate Stakeholder Session July 2015
	Consumer Advocate Stakeholder Session Demand Forecasts October 2015

4 Summary of the stakeholder feedback received

Following the release of each consultation paper and the receipt of formal submissions Ergon Energy published all submissions not marked as confidential online, along with a summary of the feedback received and our response.

The key themes of the discussions we have had with our stakeholders as we moved through the engagement journey have been around:

- The significant concern around the rise in electricity prices in recent years. This has created a tension, as network prices are a significant component of the bill, between a recognition of the need to remove the cross subsidies that exist as early as possible (and respond to the equity risk associated with new technologies) and the need for more time to ensure customers are able to respond to the changes (with considerations needed around the maturity of the market for the supporting technology).

  This has led to general support for the voluntary nature of the new tariff options now being made available and the staged introduction of other reforms, like kVA charging.

- There is a desire for a greater understanding around the customer impacts/opportunities in the new voluntary demand-based tariffs. This is seen as key to being able to educate customers appropriately and, ultimately, for them to be confident in choosing to adopt the new tariffs. It will also be important to ensuring that there are adequate protections for customers.
- There are concerns around the ability of some customers (both residential and business) to respond to the price signals and control the timing of their demand and the impact demand tariffs would have on these particular customers. However, there is a growing understanding of how the path we have been progressing on can support the best price outcome for all, over the longer term.

Throughout the engagement undertaken, it was challenging to engage on network tariffs in isolation. Much of our discussions also included matters like the Queensland Government's Uniform Tariff Policy and the relationship between Ergon Energy's network tariffs and the regulated retail prices, the approach other retailers could take in their pricing going forward, and the future roll out and cost of smart meters. There has also been considerable discussion on the emergence of energy storage, electric vehicles and other technologies as an increasingly accessible part of the energy solutions mix.

The following tables provide further detail on these themes and our response. More detailed summaries of earlier stakeholder submissions are available at: www.ergon.com.au/futurenetworktariffs.

Table 3: Concern on electricity prices and the pace of reform

Issues raised	Our response
Throughout our engagement on network tariffs and our Regulatory Proposal our customers and other stakeholders have expressed **concern about the rise in electricity prices** over recent years.[10]	Our focus is on ensuring we can deliver for the best possible price. We have been driving hard to reduce our costs as a business. Over the next five years our expenditure overall is forecast to be more than a billion dollars less than the last five years. This provides an ideal environment for tariff reform. We are also focused on enabling an effective market; with network tariff reform just one of our initiatives.
Price concerns have led to a tension between the **need to remove cross subsidies** as early as possible and the need for **more time to be able to respond** to the changes. Over 80% of attendees in our biggest open webinar were looking for us to act to remove the cross subsidies that will grow under existing charging arrangements. But they wanted change to be gradual.[11]	By acting early, we have created the opportunity for customers and our business to embrace change in a gradual manner. The progress we have made along our reform pathway means 2016-17 will be a foundation year for our position on tariffs for 2017-20. For the period of our TSS we plan to keep our tariff structures relatively stable – allowing us to build a greater understanding of the new options and promote their take up.
There is support for the new demand-based, seasonal time-of-use tariffs to be introduced as **voluntary tariffs**, as well as features like the **monthly billing cycle**. Some stakeholders recognise that there is no visibility of Ergon Energy's network tariff in the regulated retail tariff so the transition could occur at the retail level.[12]	We agree that introducing the new tariffs as optional tariffs offers a way to progress the reforms gradually, piloting them with different customer segments. Being voluntary, customers who are unsure will be able to stay with their existing tariff. Some of our large users are already taking them up.

10 Dobinson Springs and Suspension Submission August 2015.
11 Webinars, Ergon Energy Queensland Pty Ltd Submission, earlier submissions and other anecdotal feedback.
12 COTA Queensland September 2015, Queensland Consumers Association Submission August 2015 , Total Environment Centre Solar Citizens Submission August 2015 and CANEGROWERS Submission August 2015.

Issues raised	Our response
While the rationale for kVA charging is understood, there is a need for **certainty/lead times** for the implementation of kVA charging for large customers in order to allow time to respond and improve a site's power factor.[13] A number of earlier submissions queried the **methodology around the calculation of tariffs denominated in kVA** and also the excess (kVAr) reactive power charge calculation (for large customers).	We worked hard to ensure both Individually Calculated Customers (ICCs) and Connection Asset Customers (CACs) were given sufficient lead time to understand and engage with us on the change to kVA charges. We notified our intention of making changes to ICC tariffs at least 12 months prior to the changes. At the same time we expressed a desire to lag the introduction to CAC tariffs by one year. We have reviewed the further introduction of kVA tariffs and while we consider that benefits warrant extending the changes already made to the ICCs and CACs, this will not be progressed for customers using less than 4 GWh p.a. before 2020. Further stakeholder engagement on this will be undertaken. Following stakeholder consultation we adopted the concept of charging for excess reactive power above a permissible kVAr level. The permissible kVAr level is calculated by applying a compliant power factor to the premises' authorised demand.

Table 4: The need for greater understanding/education

Issues raised	Our response
Customers and other stakeholders need to be provided with **clear rationale** for the tariff reforms and evidence of longer term benefits to customers.[14]	Our objective is to ensure we can continue to meet everyone's needs into the future for the best possible price and to deliver fairer, more equitable pricing signals. The reforms aim to increase the scope for customers to respond to enhanced price signals. We have published online the external analysis provided by Energeia which quantifies the 'cost of inaction' of no tariff reform against alternative approaches to cost reflective tariffs. This analysis was discussed in our webinars and forums.
There is **limited information** around the potential price impacts/value proposition by customer segment (households, low income, solar and other technology users, industry/agricultural sectors, etc.) – particularly around the impact in the summer months/bill **stability**. The ability to assess the attractiveness, barriers and opportunities of the tariffs is needed as soon as possible. In order to implement the new demand-based tariffs there is a need to educate customers, explain the potential impact for individual circumstances, and any options to benefit or mitigate. There continues to be interest in a tariff calculator to guide individual customers.[15]	We accept that if we want successful customer uptake of cost reflective tariffs, we need to be able to educate customers on the likely impact on their bills if a change is made. Our obstacles to date have been a lack of segment and demographic data to identify 'winners and losers' from the tariff. Challenges also exist around the extrapolation of our network charge into a regulated retail tariff. Nevertheless, we are finalising plans to undertake a pilot program (targeting various customer segments) to identify issues, barriers and customer benefits of adopting the demand-based tariffs. This will provide real-life examples to demonstrate the value of new tariff structures. Stakeholder feedback has also influenced our position on the calculation of the residential Seasonal Time-of-Use Demand tariff. We have used a calculation methodology that focuses

[13] LGAQ Submission August 2015.

[14] QOSS Submission September 2015 and Queensland Consumers Association Submission August 2015.

[15] QCOSS Submission September 2015, COTA Queensland September 2015, Queensland Consumers Association Submission August 2015, Queensland Farmers Federation Submission August 2015, Total Environment Centre Solar Citizens Submission August 2015 and CANEGROWERS Submission August 2015.

Issues raised	Our response
	on the averages of a customer's peak demand to minimise the risk of 'bill shock'.
There are concerns about the **complexity** of the Seasonal Time-of-Use Demand tariffs. It is vital tariffs meet the simplicity principle and can be understood so that customers can respond to the price signals appropriately. There is some desire to have alignment with Energex/other distributors.[16]	Following stakeholder feedback, the methodology for calculating the demand charges of the new optional tariff for residential and small to medium business customers has been standardised for both the summer and non-summer charge. The pilot program will help us identify how the 'retail packaging' of the tariff can be used to assist in simplifying the tariff for our customers. We are continuing to engage with Energex to gain alignment in terminology/approach where ever possible, noting that we have different load profiles.
That there are adequate **bill protections** for vulnerable households (those with medical cooling or heating needs, Aboriginal and Torres Strait Islander customers, refugees etc.) who move to demand-based tariffs and that the reforms meet the broader definition of **equity and fairness**.[17]	Given the current Uniform Tariff Policy arrangements, employing bill protection measures at the network tariff level are unlikely to be satisfactory. We look forward to discussing possible bill protection arrangements with the QCA and our other stakeholders as retail tariffs are developed. Our decision and drive to move customers toward cost reflective tariffs is founded in equity and fairness principles. Analysis suggests that not reforming tariffs could mean that customers pay $1 billion more than they would otherwise need to in the future. The customers most at risk of paying higher prices are those that cannot afford to invest in distributed energy resources. Our goal is to provide the best possible price for all our customers, irrespective of how they use the network. The improvement in cost reflectivity and the elimination of cross subsidy are important elements of this and contribute to equity and fairness for our customer base.
The potential for an **impact on the default tariffs** for those customers who do not adopt the demand tariffs or as the use of the network continues to change with the take up of solar, energy storage or other technologies.[18]	Through 2017 to 2020, we will be operating in an environment where our revenue requirement has reduced. This will allow us to incentivise customers to move to the voluntary tariffs through the rates applied, while limiting the impact of the reforms and any change in the revenue cap (for example, due to an unexpected drop in energy sales from the take up of solar) on customers remaining on the default tariffs. Those on the default tariffs will also benefit in the longer term from the outcomes achieved from the reforms – see below.

16 QCOSS Submission September 2015, COTA Queensland September 2015 and Total Environment Centre Solar Citizens Submission August 2015.

17 QCOSS Submission September 2015.

18 QCOSS Submission September 2015, COTA Queensland September 2015 and Total Environment Centre Solar Citizens Submission August 2015.

Table 5: The ability for customers to respond

Issues raised	Our response
There are concerns around the **ability of some customers (both residential and business) to control the timing of their demand** and the impact demand tariffs would have on these particular customers. Many consider that the majority of customers will **need to respond to the price signals** and change their usage behaviour in order for the reforms to be considered a success.[19]	We believe that the case for change is based on the potential long-term positive impact for all customers and note the voluntary nature of the new tariffs. It is correct that the reforms do incentivise those that can/are willing to change behaviour. However, not everyone will need to respond to benefit from the reforms. Some are already using the network efficiently (and should be charged appropriately). Others may choose to use the network at peak times, recognising the value it delivers. Others who cannot change their behaviour will benefit from the overall response – as we will only need to invest in the network where it is valued.
There are some questions around the actual **periods of peak demand on the network** and how representative they are. There is also some concern that reflecting these periods into network tariffs (hours, days of the week and the seasonal element) may mean customers are not able to respond or that they could experience 'summer bill shock'.[20]	The periods set for our peak demand charges have been developed as required by the National Electricity Rules, from detailed analysis of the indicative daily/annual load profiles for our residential and business customers. See Appendix B. In summary, residential load peaks in summer for both weekdays and weekends between 3.00 pm and 9.30 pm. Business load peaks on summer weekdays between 10.00 am and 8.00 pm, with a lower summer weekend profile. Customers on these new tariffs also see substantial reductions in the volume charge compared to legacy tariffs and a zero fixed charge rate for the Distribution Use of System charge. Not aligning tariffs with the actual peak demand periods would interfere with the pricing signal. We are piloting the new Seasonal Time-of-Use Demand tariffs to better understand the customer response and support bill stability.
The **supporting technology**, including the required meters, needs to be accessible/affordable so that customers can respond to the price signals appropriately. There is an appreciation that new technologies could assist customers to understand the signals and to respond – however, there is a concern that low income/renters, businesses facing financial challenges, etc. may not be able to afford them. There is also a concern, most notably in the agricultural sectors, that technologies will become obsolete quickly.[21]	We are hopeful that as the technology in advanced electronic meters and the communications modules become common place, the cost will come down. This will also be the case for energy management systems and other customer technologies that are evolving. Ergon Energy will participate in future government/regulatory discussions on the roll out of smart meters, including the treatment of renters and other specific customer segments.

[19] Queensland Consumers Association Submission August 2015 and Pioneer Valley Water Submission August 2015.

[20] QCOSS Submission September 2015, Pioneer Valley Water Submission August 2015 and Queensland Farmers Federation Submission August 2015.

[21] QCOSS Submission September 2015, COTA Queensland September 2015, Pioneer Valley Water Submission August 2015 and Queensland Farmers Federation Submission August 2015.

Issues raised	Our response
It was noted that Ergon Energy could subsidise the shift to smart meters where there are network constraints and **use tariffs to help reduce peak demand**.[22]	Ergon Energy has a targeted demand management program that uses non-tariff incentives, and will look at the role of promoting/incentivising the take up of demand-based tariffs in these constrained areas.
While recognising the regulatory requirement, there is a concern about the use of the incremental **cost of meeting an additional unit of electricity demand** in regional Queensland as the basis of cost reflective pricing signals. Questions have been raised about the value (if it is affordable), and if it should be location specific, etc.[23]	Chapter 1 of our TSS outlines the unique nature of Ergon Energy's network, customer base and pricing arrangements. The outcome of this is ultimately higher costs, compared to the average network service provider. There is a full discussion on the methodology for arriving at the LRMC in Appendix B.
There is general support for a reduction in **fixed charges** for the demand-based network tariffs – as an attractive element for customers (although there is some concern for the other pricing mechanisms used).[24]	This feature is a key part of what makes the Seasonal Time-of-Use Demand tariff attractive. However, other tariffs and charges are required to reflect the fixed or sunk costs associated with the investment in the network.
There is general **support for the averaging method** used to calculate the demand tariff, as it minimises the potential for bill shock for residential and small to medium business customers. However, there was concern for the level of complexity.[25]	This calculation has been simplified by applying the same methodology of averaging for both summer and non-summer months. We will be using the pilot to test how the methodology can be communicated and packaged into a retail product offering.
The solar industry recognises the need to move to more cost reflective network tariffs, however it is concerned about the **impact on solar customers** of the demand-based tariffs. Consideration is needed around how these customers can adapt/and ensuring the tariffs are equitable.[26]	We have not sought to separately classify solar customers and customers without solar in our analysis. However, we have looked at the impact of different tariff structures against a sample of customers and the incentives of that tariff to uptake solar and storage. Where the uptake of solar and storage incentivised by the tariff has corresponding forward reductions in network costs, the cost reflectivity score is high. In our analysis we found this to be the case for business customers whose load profile is more toward the middle of the day.
Stakeholders have questioned how the **controlled load tariffs** work in the suite of tariffs to complement the new cost reflective tariffs.	In 2015-16, a process was started to rebalance these tariffs. This process will see the rates developed based on residual recovery principles, as these loads do not impact peak demand (so they do not have to recover any LRMCs). We will also look to introduce an additional controlled load tariff that supports our STOUD.

[22] Total Environment Centre Solar Citizens Submission August 2015.

[23] QCOSS Submission September 2015, Queensland Farmers Federation Submission August 2015 and Dobinson Springs and Suspension Submission August 2015.

[24] Ergon Energy Queensland Pty Ltd September 2015, QCOSS Submission September 2015, COTA Queensland September 2015 and Total Environment Centre Solar Citizens Submission August 2015.

[25] QCOSS Submission September 2015, COTA Queensland September 2015 and Total Environment Centre Solar Citizens Submission August 2015.

[26] Total Environment Centre Solar Citizens Submission August 2015.

Table 6: Retail tariff reform and other matters

Issues raised	Our response
The **Uniform Tariff Policy** and how this subsidisation through the regulated retail tariffs impacts the rates applied to the default and demand-based tariffs now and in the coming years. Ergon Energy Queensland Pty Ltd has a view that in order to support tariff reform, Ergon Energy's network tariffs should be used to develop regulated retail tariffs in future years.[27]	The timing and the degree of impact of Ergon Energy's network tariffs on the regulated retail tariffs is subject to the QCA's annual pricing determination. The Uniform Tariff Policy, how it is designed and if it should be targeted, is a topic under review by the Queensland Productivity Commission. See http://www.qpc.qld.gov.au/inquiries/electricity-pricing/. Nevertheless, we want to make sure that our network tariff structures are efficient. This will ensure that future changes to retail competition and pricing in regional Queensland are not hampered by inefficient network tariff structures.
As the impact of demand-based tariffs become clear it may be necessary for the **Queensland Government to consider policy positions, the application of concessions** and other ways to support vulnerable customers or impacted/opportunities for industries to transition to them.[28]	Ergon Energy will report to the Queensland Government and the QCA as data becomes available through our modelling and our demand-based tariff pilot.
There is general discussion around how **retailers** will reflect the network tariff structures/rates in their retail tariffs (including whether they should be required to show the network charges on the bill).[29]	The QCA supported our reform path by introducing new demand-based tariffs in July 2015 (based on our new network tariff structures). We anticipate ongoing support as we move forward. This will allow Ergon Energy Queensland Pty Ltd, our retailer, to offer tariff choices that reflect our changes in network tariffs. Ergon Energy has also been engaging with all of the retailers operating in our service area on the new voluntary tariffs, and we have already seen large customers choosing to move to the voluntary Seasonal Time-of-Use Demand tariffs.
Questions were raised about Ergon Energy's **pricing zones**, most notably using the East Zone to develop the tariff structures that apply to the West and Mount Isa Zones.[30]	Unlike most other DNSPs, Ergon Energy develops prices for three different pricing zones. These are based on geographic areas of the network where costs are assessed to be broadly similar. It is not seen as necessary to differ the tariff structures by zone, only the rates. User groups are the only area that you see significant differences in network costs and demand drivers.
There needs to be the ability for customers to **shift seamlessly between the Standard Asset Customer classes**, as they move above and below the annual 100 MWh usage level.[31]	This is likely to be a matter raised with the Queensland Government as it impacts the retail tariffs available to the customer. Traditionally customers consuming above 100 MWh per annum have had access to metering technology which has allowed more options in terms of tariff design. As metering arrangements evolve, there will be more opportunity to align cost reflective tariffs for all business customers, noting that there are some differences between small business customers and larger commercial and

27 QCOSS Submission September 2015, COTA Queensland September 2015, Queensland Consumers Association Submission August 2015 and Queensland Farmers Federation Submission August 2015.

28 QCOSS Submission September 2015, Queensland Farmers Federation Submission August 2015 and Dobinson Springs and Suspension Submission August 2015.

29 COTA Queensland September 2015.

30 COTA Queensland September 2015 and Queensland Consumers Association Submission August 2015.

31 Ergon Energy Queensland Pty Ltd Submission October 2015.

Issues raised	Our response
	manufacturing sites.
Access to **affordable, appropriate metering** is raised as a potential barrier to the implementation of cost reflective tariffs. Many noted the Australian Energy Regulator's recent changes to metering charges, and the need for more information on the future roll out of advanced meters. There was also discussion around the treatment of customers already using electronic meters.[32]	Ergon Energy is participating in the policy discussions around metering. In order for our customers to access cost reflective tariffs, metering upgrades are likely. It is in our best interest to allow our customers access to affordable metering to allow them to adopt these tariffs and we will continue to work with regulators and policy makers to allow this to happen.
As energy storage is taken up, Ergon Energy needs to reconsider the **current restrictions on the size of solar systems** that can be connected to the network, and the value of solar exported to the grid.[33]	Our consultation on pricing reform has not extended to connection arrangements around the size of solar installations. Ergon Energy enjoys one of the highest rates of solar penetration in the world. We are looking for ways to leverage this solar for the benefit of all customers. In order to provide the best possible price for all customers we want to encourage choice as to how customers use the network without inefficiently increasing the price that other customers would pay. Ergon Energy will continue to review our standards for the connection of micro-embedded generating units to the network as technologies in this area develop.

[32] QCOSS Submission September 2015, COTA Queensland September 2015, LGAQ Submission August 2015, Queensland Farmers Federation Submission August 2015 and Total Environment Centre Solar Citizens Submission August 2015.

[33] Total Environment Centre Solar Citizens Submission August 2015.

Appendix B Long run marginal cost methodology for Standard Control Services

1 Introduction

1.1 New pricing principles

In late 2014, the Australian Energy Market Commission (AEMC) made a suite of changes to the National Electricity Rules (NER) that, inter alia, modified the pricing principles in clause 6.18.5. Amongst other things, these changes increased the weight placed on Long Run Marginal Cost (LRMC) in tariff-setting. The pricing principles in clause 6.18.5(f) of the NER now require each tariff to be "based on" the LRMC of providing the service to the retail customers assigned to that class, with:

- the method of calculating such costs
- the manner in which that method is applied

to be determined having regard to:

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

Clause 6.18.5(g) of the NER now provides that the revenue to be recovered from each tariff must:

- reflect the Distribution Network Service Provider's (DNSP) total efficient costs of serving the customer tariff class
- when summed across all tariffs, permit a DNSP to recover its allowed regulated revenue
- comply with the above in a manner that minimises distortions to the LRMC price signals resulting from the application of clause 6.18.5(f) of the NER.

Under clause 6.18.5(h) of the NER, a DNSP must consider the impact of tariff changes on retail customers and may set tariffs at variance from the LRMC for a transitional period (which may extend beyond one regulatory control period) to the extent the DNSP considers this reasonably necessary having regard to:

- the desirability of tariffs complying with the pricing principles, including the need to reflect LRMC
- the extent to which retail customers can choose the tariff to which they are assigned
- the extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions.

Finally, clause 6.18.5(i) of the NER provides that the structure of each tariff must be reasonably capable of being understood by retail customers assigned to that tariff.

These changes to the NER followed the AEMC's 2012 Power of Choice Review, which was intended to increase the economic integrity of signals faced by end-use electricity customers and to increase the scope for them to respond to these enhanced signals. Policy-makers took the view that if retail customers faced tariffs that better reflected the costs of meeting demand, they would have incentives to change their behaviour in ways that could reduce overall system costs.

1.2 Focus on LRMC

As highlighted above, Ergon Energy has new obligations to set tariffs for each customer tariff class based on the LRMC of providing the relevant service to that class. The NER previously required that each tariff and, if it consisted of two or more charging parameters, each charging parameter of a tariff class, "take into account" the LRMC for the service or, in the case of a charging parameter, for the element of the service to which the charging parameter relates. There was no specific definition of LRMC in the previous framework.

The NER now defines LRMC as the cost of an incremental change in demand over a period of time in which all factors of production required to provide those services can be varied. This definition incorporates the investment required over time to maintain and expand capacity in the network to meet future demand. The method of calculating and applying LRMC must have regard to a number of considerations including the:

- costs and benefits of each approach to calculating and applying a particular tariff formulation
- additional costs likely to be associated with meeting demand from the customers assigned to the tariff at times of greatest utilisation of the relevant part of the distribution network
- geographic location of customers assigned to the tariff and the extent to which costs might vary between different locations in the distribution network.

To the extent that tariffs based on LRMC do not recover the total efficient costs of serving the customers assigned to the tariff, or do not enable us to recover our regulated revenue, we are permitted to apply other tariff components or approaches to meet those requirements. Importantly, however, any additional tariff components or other approaches to setting tariffs must influence customers' behaviour as little as possible relative to the behaviour arising under 'pure' LRMC tariffs.

1.3 Consultation on LRMC

In response to the new NER obligations, Ergon Energy prepared or commissioned a number of reports, which we used to consult with customers on our approach to calculating and applying LRMC to network tariffs. These reports were:[34]

- Consultation Paper: *Aligning Network Charges to the Cost of Peak Demand* (Long Run Marginal Cost), March 2015
- Supporting Document: *Long Run Marginal Cost Considerations in Developing Network Tariffs*, March 2015 (LRMC considerations report)
- Supporting Document: *Estimating the Average Incremental Cost of Ergon Energy's Distribution Network* by consultant, Harry Colebourn (the Colebourn report)
- *Maximum Demand Tariff Analysis Report* by consultants Energeia.

These reports explain our LRMC calculation methodology as well as how LRMC could be applied to our tariff structures and rates. These topics are discussed in the following sub-sections.

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[34] All these reports are available on Ergon Energy's website at www.ergon.com.au/futurenetworktariffs.

2 Principles underlying LRMC

2.1 Rationale for marginal cost pricing

The reason policy-makers have increased the NER's emphasis on setting tariffs to reflect LRMC is grounded in economic theory. Economics suggest that society's resources will be allocated most efficiently when prices reflect the marginal cost of supplying the goods or service in question. 'Marginal cost' refers to the incremental or avoidable cost of providing one more or one less unit of the relevant goods or service. Put differently, it is the change in the total costs of providing a good or service when satisfying an additional unit of demand.

The reason why prices reflecting marginal cost should maximise efficiency is that at such prices, customers will only increase their consumption if the value they place on consuming more of the goods or service at least equals the incremental value of the resources used up to provide that goods or service. So long as customers value an additional kWh of electricity as much as the value of the resources required to provide it, it is efficient for customers to consume more electricity. Conversely, if customers place a lower value on an additional kWh of electricity than the costs of providing it, society would be better off if the resources required to provide that kWh were allocated in a different way.

In many contexts, the application of marginal cost pricing is fairly straightforward and provides a comprehensive solution to how prices should be set to promote efficiency. However, the 'natural monopoly' characteristics of distribution network infrastructure can make the setting of optimal network prices a more complex exercise. These characteristics include:

- economies of scale in the provision of distribution networks
- 'lumpiness' of network infrastructure
- 'sunk' costs – investment in network assets cannot usually be reversed if the assets are made redundant or their full capacity is no longer required.

These characteristics give rise to two key dilemmas for policy-makers in setting principles for efficient network tariffs:

- how should marginal cost be defined
- how should regulated network revenue not recovered through marginal cost tariffs be recouped.

2.2 How should marginal cost be defined?

The definition of marginal cost can vary depending on the extent to which different inputs are regarded as fixed when assessing how total cost changes in response to an increase in demand. Although there is not necessarily a relationship between the proportion of a business's inputs that are fixed and particular lengths of time:

- Short Run Marginal Cost (SRMC) refers to marginal cost when at least one input is fixed – this corresponds to a timeframe of minutes, hours, days, weeks or months, depending on the industry in question
- LRMC refers to marginal cost when all inputs can be changed – this often corresponds to a timeframe of months or years (sometimes decades), again depending on the industry.

For electricity distribution networks, due to economies of scale and the 'lumpiness' of distribution network investment, the conservative nature of most distribution reliability standards and the fact that capital expenditure on the existing network are largely sunk, the SRMC of a network service will typically be limited to variable operating costs. There is also an incremental effect on distribution losses, which forms part of market settlements. Conversely, the LRMC of a network service will typically be much higher than the SRMC because LRMC incorporates the longer run investment cost implications of higher demand.

Setting tariffs to reflect LRMC can provide more useful long-run signals to customers about the implications of their increased demand for network services at peak utilisation times. As customers and prospective customers make decisions to invest in particular types of facilities and/or locate in particular geographic areas, LRMC-based tariffs should encourage them to take into account the cost consequences of their decisions. Further, by incorporating network capital costs, LRMC-based tariffs should recover a much larger proportion of total network costs than SRMC-based tariffs. These considerations explain why the AEMC has traditionally favoured LRMC as the basis for setting distribution network tariffs and why the recent Rule change increased the emphasis placed on LRMC.

2.3 How should residual costs be recouped

Setting tariffs to reflect marginal cost – even LRMC – will typically not, by itself, allow a distribution network to recover all of its historical capital costs. This follows from the economies of scale inherent in network provision and the lumpiness of network investment. Together, these characteristics can usually cause the marginal cost to fall below the average cost of providing the network. To the extent that the magnitude of a DNSP's historical capital expenditure drives the determination of its allowed regulated revenues, this means that setting tariffs equal to LRMC may not enable a distribution network to recover its total regulated revenues.

As noted in Section 1.1 above, clause 6.18.5(g) of the NER permits DNSPs to modify or supplement LRMC-based tariffs to enable them to recover their total regulated revenues. However, any supplements to LRMC-based tariffs must be designed to influence customers' behaviour as little as possible relative to the behaviour that would arise under 'pure' LRMC-based tariffs. This requirement seeks to preserve, as far as possible, the behavioural signals provided by LRMC-based tariffs.

Accordingly, residual cost recovery tariffs that achieve this objective are described by economists as 'least-distortionary' tariffs, where the 'distortion' in question is defined in terms of the behaviour resulting from marginal cost-based tariffs. Therefore, residual cost recovery tariffs should be structured so as to have the smallest possible unintended impact on customers' consumption decisions.

The best way, theoretically, to set the mark-ups or supplementary tariffs is to recover residual network costs from customers in proportion to their overall willingness to pay for the provision of the distribution network.

Customers are still likely to continue to use the network if the charge added to LRMC and recovering residual costs is set in a way that means their overall network bill remains below their overall willingness to pay for access to the distribution network. Conventional economic thinking would argue against setting tariffs based on a customer's actual usage of the network (e.g. actual electricity consumption), as this may inefficiently deter the utilisation of sunk assets. Notwithstanding this, legacy energy based tariffs applied to most small customers with accumulation meters do not offer an alternative

3 Calculating LRMC

Conceptually speaking, there are a number of ways to interpret and calculate LRMC.

The NER does not prescribe a method of determining the LRMC of serving customers in a given tariff class beyond the considerations set out in clause 6.18.5(f). The AEMC's accompanying final determination also did not prescribe a particular methodology for determining appropriate LRMCs. Rather, the AEMC discussed various methodologies for calculating LRMC and concluded:

> *The Commission considers that there is merit in providing flexibility to use either the AIC or Perturbation methodologies, or other accepted methodologies, depending on how strong the LRMC price signals need to be in order to send signals to consumers about the cost or benefit of undertaking or deferring additional network expenditure.*[35]

The following sections set out the methodology and approach we have used to calculate the LRMC, with a summary provided in Table 1.

Table 1: Summary of changes to LRMC

Issue	Actual and proposed changes
Choice of method for calculating LRMC	Average Incremental Cost (AIC) approach with separate verification using a Long Run Incremental Cost (LRIC) approach as adopted in 2014-15 Consistency check against LRIC model as used by United Kingdom (UK) distributors (termed the 500 MW model)
Costs to be included in LRMC for AIC	Network demand related capital costs Incremental operating and maintenance expenditure associated with the demand related capital costs
Approach to estimating LRMC using LRIC	A hypothetical greenfield model to supply a demand of 500 MW using modern asset replacement, operation and maintenance costs Model uses Ergon Energy's system configuration and voltage levels and achievable levels of asset utilisation

3.1 Methodology used for calculating LRMC

The AIC methodology has been used for deriving the estimates of LRMC we will apply in tariff-setting. As explained in our LRMC considerations report, while the Perturbation (Turvey) method is perhaps the most conceptually 'pure' method of estimating LRMC, it is also the most resource-intensive and involves the greatest degree of subjectivity in selecting perturbation scenarios.

In accordance with clause 6.18.5(f) of the NER, we have taken the view that, given the data and time available to us and the costs and resources required to generate perturbation estimates of LRMC, the benefits of developing such measures do not presently outweigh the costs.

35 AEMC (2014), *Rule Determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014, p118.

With respect to the determination of more geographically-refined AIC-based estimates of LRMC, we also note that we do not have sufficiently granular information on growth and expenditure to calibrate a specific AIC-based LRMC estimate in the West Zone at this time. However, previous analysis suggested an uplift factor of 2.5 times the East Zone level to account for the sparse footprint of customers in the West Zone.

Going beyond network zone-level LRMC estimates, we are still exploring whether – if more locationally-granular tariffs are developed – they should vary by geographic location or by electrical location (i.e. proximity to core sub-transmission (ST) and high voltage (HV) network assets). This will be further investigated following finalisation of the TSS process.

Finally, we have considered whether it would be feasible to utilise zone-wide AIC LRMCs immediately and more localised AIC-based or perturbation-based LRMCs later in this regulatory control period. However, we have decided against such a strategy. To do so without revising the TSS would be cost prohibitive and require us to develop a number of 'sleeper' tariffs that would initially be identical and only vary if and when we decided to apply more localised LRMC estimates. The NER does not appear to allow a DNSP to seek amendments to its TSS for no reason other than having developed more localised estimates of LRMC.

3.2 Costs for inclusion in LRMC estimate

The conceptual approaches to LRMC do not address the issue of which costs ought to be included in the calculation of LRMC and whether different costs should be included in determining LRMCs for different customers.

The categories of costs that could potentially be included in the determination of LRMC can be considered across a number of dimensions:

- type of cost – the nature of costs that could be included in an LRMC calculation could span the following range: augmentation capital expenditure, replacement capital expenditure, connections expenditure (net of capital contributions) and operating and maintenance expenditure (which may be asset-related or non-asset-related)
- network level – the nature of costs that could be included in an LRMC calculation could span the following range: ST bus, ST lines, zone substation (ZS), HV bus, HV lines, distribution substation, low voltage (LV) bus and LV lines
- geography – network zone or locational characteristics/customer density (e.g. urban/suburban/rural/remote).

The guiding principle for whether a cost should be included in the calculation of LRMC is causation or, alternatively, avoidability. If an incremental increase or decrease in a customer's demand could affect the size or timing of a cost, then the cost should be included in the calculation of the LRMC applicable to that customer.

3.3 Inputs to AIC calculation

This section provides information on the source of the data used in the AIC calculation.

The basic formulation of the AIC in $/kW/year is as follows.

$$AIC = \frac{NPV(Demand\ related\ capital\ cost, \$/yr + Incremental\ O\&M, \$/yr)}{NPV(Incremental\ network\ demand, kW)}$$

Where:

Demand related capital cost is the annual increment in capital cost, calculated using a capital recovery factor for the incremental capital expenditure. An asset life of 40 years is assumed for this calculation.

Incremental O&M is the annual increment in operating and maintenance expenditure, calculated as a percentage of the incremental capital expenditure.

Incremental network demand is the year-on-year increase in demand in kW.

The specific components that Ergon Energy has included in its AIC formula are as follows.

<table>
<tr><th colspan="2">Numerator – incremental annual costs</th><th>Denominator – incremental demand</th></tr>
<tr><td rowspan="3">Annual cost of incremental capital expenditure using an asset life of 40 years and</td><td>• Augmentation expenditure (Augex) by system level</td><td>• Incremental annual demand growth in kW by voltage level</td></tr>
<tr><td>• 50% of net Connections expenditure (less capital contributions) associated with upstream reinforcements rather than locational extensions</td><td>• 50% of annual connections growth in kW arising from local augmentations to meet relocated demand</td></tr>
<tr><td>• 2.5% of Replacement expenditure (Repex), assessed as providing a useable network capacity increase through modern equipment</td><td>• Nil –the increased capacity from Repex is taken up by demand growth above</td></tr>
<tr><td colspan="2">Annual Operating and Maintenance (O&M) expenditure associated with the above capital expenditure, based on a percentage of the asset costs.</td><td></td></tr>
</table>

To the extent possible, the information has been extracted from the AER's Distribution Determination in October 2015.

The principal inputs to the AIC calculation are as follows:

- Network demand related capital costs. These are subsets of the capital expenditure allowances in the AER's Distribution Determination. Capital costs associated with demand growth and a portion of connection expenditure (50%)[36] primarily comprise the category of "demand related" capital costs. A small (2.5%) share of replacement expenditure (repex) capital costs have been included as modern equipment typically has higher useable capacity than that replaced.
- The incremental network demand. This is taken from the information provided to the AER and accepted as part of the October 2014 Regulatory Proposal. This demand growth is a net total that includes connections, disconnections and changes in demand at existing locations. Consequently, a proportion (50%) of the new connections growth has been included. New connections growth is offset by reduced load and disconnections occurring elsewhere in the forecast demand growth but requires local augmentations in many instances.

[36] In 2016-17 Ergon Energy adjusted the proportion of Connection expenditure (less capital contributions) used in AIC calculations from 100% to 50%. This recognises that not all of this expenditure is demand related.

- Weighted average cost of capital (WACC). We have applied a real vanilla Weighted Average Cost of Capital of 3.42%, consistent with the Distribution Determination.

Capital costs

There are four main sources for demand related capital costs:

- ***Capitalised overheads*** are allocated to the three capital expenditure categories below. These overheads represent an uplift of approximately 44% on the direct capital costs below.
- ***Augmentation expenditure*** (augex). The augex forecast is then stratified into the functional levels below based on mapping from information provided in response to RIN requests from the AER.

Table 2: Sources of demand related capital costs

RIN entry	Functional Level				
	ST	HV bus	HV net	LV bus	LV net
Overhead Sub-Transmission Lines	100%				
Underground Sub-Transmission Cables	100%				
Overhead Distribution Lines			83%		17%
Underground Distribution Cables			83%		17%
Distribution Equipment			83%		17%
Substation Bays		100%			
Substation Establishment		100%			
Distribution Substation Switchgear				100%	
Zone Transformers		100%			
Distribution Transformers				100%	
Low Voltage Services					100%
Communications – Pilot Wires	50%		50%		
Other Equipment	100%				
Control Centre - SCADA	50%		50%		
Land & Easements (System)	50%		50%		

Augex is grossed up by the allocated capitalised network and corporate overheads above and projected beyond the regulatory control period 2015-20 to 2039-40 using the average expenditure during the period.

- ***Connections expenditure*** is set out in RIN Table 2.5.2 by the connection type and the voltage of connection. The connections expenditure at HV and LV levels is separated for use in the AIC calculation, grossed up by capitalised overheads and projected to 2039-40. The connections expenditure is offset by the ***Capital contributions*** made by customers. Customer contributions are set out in RIN Table 2.1.1. However, an updated version of the capital contributions forecast was used. This was apportioned between the HV and LV functional levels in the same ratio as the connections expenditure and projected in the same manner.
- ***Repex*** is not normally associated with demand growth but a proportion of repex results in increasing the capability of assets as modern equivalent assets frequently have higher capacity

than those they replace. A small proportion (2.5%) of repex expenditure has therefore been included in the AIC calculation. Repex is set out in RIN Table 2.2, with approximately 100 categories of expenditure. These have been separated into the five functional system levels. The resulting costs have been grossed up by capitalised overheads and projected to 2039-40.

Operating and maintenance costs

Forecast operating expenditure was assumed to represent 1.5 - 2.5% of the Optimised Replacement Cost of Ergon Energy's assets. Assets at higher voltage levels tend to be more costly (capital intensive) whereas those at lower voltage levels are less so and more maintenance intensive. In addition, the operating expenditure on newly commissioned assets was phased in during the years following asset commissioning, as shown below (Year 0 is the year of commissioning). This reflects the fact that newly commissioned assets do not require full maintenance for a period.

Table 3: Forecast operating expenditure

System level	Year 0	Year 1	Year 2	Year 3	Year 4
ST	0	1.5%*60% = 0.9%	0	0	1.5%*40% = 0.6%
HV	0	2.0%*60% = 1.2%	0	0	2.0%*40% = 0.8%
LV	0	2.5%*60% = 1.5%	0	0	2.5%*40% = 1.0%

The above percentages are applied to the forecast of net capital costs:

Net capital expenditure = (augex + connections + repex – contributions)

The outcome is a forecast that represents the annual incremental operating expenditure associated with demand capital expenditure at the three system levels.

Incremental demand

Incremental demand for the LRMC calculation requires a demand forecast for each functional level of the network. To derive this, Ergon Energy's Transmission Connection Point coincident maximum demand was projected to 2039-40, in a similar manner to the capital expenditure forecast, using the average growth rate. Forecast energy growth rates for each tariff group were used to estimate the HV and LV demand growth and ST formed the residual to balance to the overall network demand forecast. The demand increment to calculate the AIC for the HV and LV system levels was adjusted to reflect:

- increased demand from new and upgraded connections
- declining demand arising from customer disconnections, energy efficiency and customer preferences.

Rate of return and annual capital recovery

Both financial and non-financial parameters were discounted to Net Present Value using the real vanilla Weighted Average Cost of Capital of 3.42%, consistent with the AER's Distribution Determination. To convert the capital expenditure into an annual cost increment, a capital recovery factor (annuity) has been used. Over a period of 40 years, this capital recovery factor was calculated at 4.63% per annum.

Power factor

The costs in $/kW need to be converted from $/kW to $/kVA for application to those customer tariffs denominated in kVA. The compliance level of power factor for most customers (0.90) was used for this conversion.

Calculation outcomes

The results are summarised in Table 4 below. The AIC is compared with the total revenue through tariffs for the system level concerned.

This analysis thus provides AIC values for Ergon Energy's tariff-setting in the range set out below for the East tariff zone.[37]

Table 4: AIC range, by system level

System level	$/kVA p.a.	AIC/Average cost
ST	$19 - $22	16% - 18%
HV bus	$66 - $78	25% - 30%
HV line	$198 - $236	43% - 51%
LV bus	$246 - $294	37% - 54%
LV line	$308 - $368	50% - 60%

Using the LRMC calculation for the peak charging component

Under clause 6.18.5(h) of the NER, a DNSP must consider the impact of tariff changes on retail customers and may set tariffs at variance from LRMC for a transitional period (which may extend beyond one regulatory control period) to the extent the DNSP considers this reasonably necessary. Ergon Energy has not applied the full LRMC calculation to the peak charging component when setting all LRMC-based tariffs. Instead, we have applied a proportional weighting to different tariffs, taking into account:

- the impact of tariff changes on retail customers
- the expectation in the NER that there would be a period of transition toward LRMC-based prices
- the relative uncertainty of key inputs over the long-term, noting the assumptions are based on the October 2014 Regulatory Proposal.

[37] Prices of HV and LV inclusive of costs of higher voltages.

The below table summarises the level of LRMC applied to the peak charging component for each customer class. These have been set having regard to the AIC outcomes above and the need to ensure that pricing changes for customers are not subject to undue variation.

Table 5: LRMC charges

Customer class	Zone	LRMC applied per annum
CAC – 22/11 kV Lines	East	$159/kVA
	West	$543/kVA
CAC – 22/11 kV Bus	East	$110/kVA
	West	$330/kVA
CAC – Higher voltages	East	$33/kVA
	West	$83/kVA
SAC Large	East	$ 212/kW
	West	$531/kW
	Mount Isa	$ 212/kW
SAC Small Residential	East	$ 212/kW
TOU Demand only	West	$531/kW
TOU Energy only	West	$590/kW
	Mount Isa	$ 212/kW
SAC Small Business	East	$ 212/kW
TOU Demand only	West	$531/kW
TOU Energy only	West	$590/kW
	Mount Isa	$ 212/kW

4 Conceptual considerations in applying LRMC

4.1 Ex ante and ex post signalling

The theoretically ideal way to apply the LRMC to the setting of network tariffs is to impose a charge equal to LRMC on each customer's demand at the time of peak utilisation of the part of the network that serves the customer's incremental demand.

If this time were known with certainty in advance – say, it was time t* – it would be ideal to set a tariff for all customers equal to $LRMC on their individual demand at t*. As customers would know the level of the LRMC-based tariff and would be able to predict the timing of t*, customers would face appropriate signals for incremental demand at the time when the network that serves them was most stretched.

Example

If the LRMC of serving additional demand at times of peak network utilisation was $100/kW/year, customers would receive a bill equal to their individual level of demand (in kW) at the peak utilisation time (t*) multiplied by $100.

Customers would then have incentives to:

- reduce their demand at t* if they expected to receive *less* than $100/kW benefit from incremental consumption at t*
- increase their demand at t* if they expected to receive *more* than $100/kW benefit from incremental consumption at t*.

Practical implications

However, as the timing of peak demand on different segments of the network is not known with certainty in advance, there are two broad options for structuring LRMC-based tariffs:

- impose an LRMC-based tariff in an ex post manner, charging customers by looking back at where their demand happens to be at the time of greatest utilisation of the network in the relevant month/season/year (ex post charging)
- impose an LRMC-based tariff in a way that reflects the expected probability of the timing of the greatest utilisation of the relevant part of the network (ex ante probabilistic charging).

4.2 Ex post charging

Under ex post charging, customers would be charged the LRMC rate on whatever their demand happens to be at the time of greatest utilisation of the relevant part of the network that serves them. In this way, customers would pay a charge equal to the LRMC they impose on the network.

The key economic benefit of ex post charging is that it provides customers with incentives to discover and utilise relevant information right up until real-time in order to minimise the costs they impose on the network. Given that the timing of peak network utilisation is uncertain, ex post charging would provide customers with incentives to use whatever information they could cost-effectively obtain to try to predict when the peak might be.

Ex post charging at the end-use customer level is, however, extremely rare. If applied, customers would not know the price they would have to pay on their network usage at the time of their usage. Customers would only know how much they were charged after the timing of peak network utilisation was established. In addition, most of Ergon Energy's residential and small to medium business customers are unlikely to be particularly well-informed or responsive to information about likely peaks in network utilisation. This suggests that ex post charging will not produce economically efficient outcomes.

4.3 Ex ante probabilistic charging

Most existing network tariff levels and timings are set in advance of when they apply, providing customers with certainty over how much they will be charged if they utilise the network at different times and in different ways. For example, Ergon Energy's published approved tariffs in each annual Pricing Proposal provide customers with all the information they need to estimate their total network charges from their intended electricity usage decisions. A customer on any given tariff can predict with a high degree of precision what the bill is likely to be if the customer consumes particular amounts of electricity at particular times.

The drawback with ex ante tariff structures is that because the precise timing of peak network utilisation each season or year is highly uncertain, it is not possible to structure tariffs in a way that will precisely reflect the LRMC of utilising the network at different times throughout a regulatory control period. Tariffs can only be structured on an expected probability-weighted basis, requiring

Ergon Energy to make an assessment – months or even years ahead of real-time – of when episodes of peak network utilisation are most likely to occur.

This is the rationale behind DNSPs setting different tariff rates for designated 'peak' and 'off-peak' periods. However, not only is the appropriateness of such designated periods often very approximate initially, it is also likely to change over time as network conditions change. This drawback is exacerbated by the NER requirements around the TSS, which require the timing of tariff structure periods to be fixed during the course of a regulatory control period unless the TSS is amended (and subsequently approved by the AER).

Despite its limitations, ex ante charging is by far the most common approach to setting network tariff structures. Nevertheless, it may be possible to design ex ante tariff structures in ways that capture at least some of the benefits of ex post charging in terms of utilising more timely information about network utilisation peaks:

- To the extent that the timings of individual customer's maximum demands are correlated to the timing of network utilisation peaks, charges based on individual customer's maximum demands may provide better signals than charges based on average demand (i.e. consumption) over a pre-determined peak period.
- To the extent the timing of a customer's individual maximum demand may not coincide with the timing of the system peak demand, some form of averaging approach may be more appropriate because an individual maximum demand tariff could inappropriately:
    - penalise individual customer's efficient demand peaks
    - fail to deter inefficient customer demand outside individual customer demand peaks.

The remainder of this appendix will refer only to ex ante tariff structure options.

4.4 Tariff options for signalling LRMC

The potential range of ex ante tariff options for signalling LRMC to customers is very wide. This section outlines the key varieties of tariffs that could be used and proposes some criteria for choosing between them to best signal LRMC.

For the purposes of providing illustrative examples, we have assumed a hypothetical LV LRMC of $420/kW/year (being $378/kVA divided by an assumed residential power factor of 0.9).

Maximum demand tariffs

The two most common forms of maximum demand tariffs are based on an annual or monthly maximum demand charging mechanism. For example:

1. Maximum annual demand – using our hypothetical LRMC the customer would pay $420/kW x maximum demand (in kW) during designated peak periods (e.g. 10.00 am to 8.00 pm working summer weekdays) within the year.

2. Monthly maximum demand – customer pays $140/kW x monthly maximum demand (in kW) during designated peak periods each month.

3. Average demand – customer pays based on its average demand during designated peak periods (e.g. $420/[no. peak hours] x average peak period demand (in kW)). Shoulder period tariff rates may be appropriate in some instances.

4. Critical peak pricing – customer pays based on its average demand during a finite number of dynamically notified peak periods 24 hours ahead of time. Peak prices are highest under this tariff due to more targeted peak period setting.

There are a number of different ways to calculate a customer's contribution to network peak demand during the peak period and some that we have investigated are outlined below.

Top 'n' maximum demand tariffs

One variant of the maximum demand tariff is to vary the charging method so that the customer pays a charge based on a simple average of its highest 'n' demands over the relevant period. For example, if n=4 and the customer's:

- highest maximum half-hourly demand during the designated peak period is 5 kW
- second-highest maximum half-hourly demand during the designated peak period is 4.5 kW
- third-highest maximum half-hourly demand during the designated peak period is 4 kW
- fourth-highest maximum half-hourly demand during the designated peak period is 3.5 kW

then the customer pays the LRMC rate x 4.25 kW (being [5+4.5+4+3.5]/4). If we apply the LRMC on a seasonal basis with the relevant period being a summer month, the LRMC rate is $140/kW ($420/3). On this basis, the customer would pay $595 for the month. If the relevant period is an entire summer or year and the LRMC rate is $420/kW/year then the customer would pay $1,785 for the year.

Top 'n' average demand tariffs

A similar arrangement would apply if an averaging approach was applied to demands within the designated peak period, rather than a maximum. For example, if n=4 and the customer's:

- highest average half-hourly demand during the designated peak period is 3 kW
- second-highest average half-hourly demand during the designated peak period is 2 kW
- third-highest average half-hourly demand during the designated peak period is 2 kW
- fourth-highest average half-hourly demand during the designated peak period is 1 kW

then the customer pays the LRMC rate x 2 kW (being [3+2+2+1]/4). If we apply the LRMC on a seasonal basis with the relevant period being a summer month, the LRMC rate is $140/kW ($420/3). On this basis, the customer would pay $280 for the month.

Scaled maximum demand tariffs

Peak demand charges in the tariff may be scaled down to reflect the level of diversity between individual customer's maximum demands and the timing of greatest network utilisation. For example, if the sum of individual customers' maximum demands during the designated peak period (300 MW) is three times the level of peak network loading (100 MW), the LRMC rates are scaled down by two-thirds.

This scaling is greater the longer the designated peak periods. For example, if the designated peak period is all year, then the sum of individual customers' maximum demands will be larger than if the peak period were only 20 hours a year. Scaling ensures that:

- the DNSP recovers its forecast avoidable costs through the LRMC element of its tariff
- if customers increase or decrease their individual demand profile in response to the tariff, the amount the DNSP needs to recover from residual cost charges does not change.

Revenue reconciled demand or energy tariffs

The forecast coincident demand of the tariff (applied to a number of customers) is used to determine the aggregate contribution of the customers on that tariff to the LRMC:

Tariff contribution = LRMC rate x forecast coincident demand

The tariff contribution is then converted into a demand or peak energy rate to apply during the peak periods when the network demand is expected to occur:

Demand (or peak energy) rate = tariff contribution/tariff volumes (kW or peak kWh)

This form of tariff-setting is expected to deliver the appropriate contribution towards the network LRMC.

4.5 Criteria for choosing between LRMC signalling structures

The process of choosing the best available tariff structure for signalling LRMC involves:

- assessing the extent to which and manner in which real-world conditions diverge from the theoretical conditions described in Section 4.1 above
- assessing the likely empirical consequences of making various compromises or trade-offs between different tariff options, taking account of the risks of under- or over-signalling the LRMC to different customer classes under each tariff structure.

This involves the following considerations:

- Should the tariff be based on a customer’s individual maximum demand or their average demand across a designated peak period?
- If a top ‘n’ tariff is applied to Standard Asset Customer (SAC) Small customer’s individual maximum demands:
    - are customers likely to reduce their maximum and system peak coincident demands in the same proportions, or
    - are they likely to respond by flattening the shape of their load profiles?
- Whether scaling should be applied depends on the respective risks and costs of over- and under-signalling the cost of consumption at the time of the system peak demand.

Examples

A stylised example Ergon Energy sometimes uses to test the appropriateness of alternative tariff structures is the comparison between two hypothetical SAC Small residential customers known as the ‘party house’ and the ‘air-con house’:

- The party house represents a customer who throws a monthly party but is otherwise often absent – this customer has a monthly maximum demand of 8 kW but its next seven-highest monthly demands are only 4 kW.
- The air-con house represents a customer who is typically home and runs air-conditioning daily – this customer has a monthly maximum demand of 8 kW and its next seven-highest monthly demands are also 8 kW.

Assuming the probability of the network peak demand is the same across all designated peak periods then an average demand tariff would provide an LRMC signal against equally probably network peak times.

Conversely, if the customer’s individual maximum demands are correlated to each other and to the network peak, an individual customer's maximum demand provides information about the timing of the network peak demand and a tariff that applies an LRMC signal against the individual's maximum demand would appear appropriate.

The more realistic case is that individual customer's maximum demands will not be correlated and the probability of network peak demand will not be the same. In this case it may be more appropriate to apply a top 'n' maximum demand tariff. If n=8 and the LRMC rate was $120/monthly average maximum demand kW/year, this would produce the following monthly charges (assuming no scaling) for the:

- party house: $540/month – based on [(8 kW+(7x4 kW))/8x$120]
- air-con house: $960/month – based on [(8x8 kW)/8x$120].

For residential and small to medium business customers, it may be the case that the combined individual customer demands within a window (rather than the individual's maximum demand) provides information about the timing of network peak demand. In this case a combination of an averaging of demands within a period across a top 'n' days may be an appropriate application.

The application of scaling would reduce these charges on a proportionate basis. A peak tariff similar to the one described above could also be applied in this situation. As the probability that the party house will impact at the time of peak demand for the ZS is less, this outcome seems reasonable.

5 Our approach to applying LRMC-based tariffs

5.1 Practical considerations

As noted above, the policy objective behind the increased NER emphasis on setting tariffs to reflect the LRMC is to enhance economic efficiency. If prices reflect marginal cost, customers will consume and producers will produce electricity when, where and to the extent that maximises society's overall welfare. It appears that policy-makers formed the view that some of the investment in network infrastructure that occurred over that period may have been avoided if network tariffs better reflected the LRMC over the last decade.

In more recent times, as the pace of network investment has declined, the source of the benefit from setting tariffs based on the LRMC has shifted away from avoiding network investment towards avoiding inefficient investment in distributed energy resources (DER).

The inefficiency arises when customers who invest in DER do not necessarily reduce our costs to serve. However, under existing tariffs they are able to avoid paying for a much larger share of Ergon Energy's costs. This can occur because the bulk of network charges to SAC Large and SAC Small customers are recovered directly or indirectly on the basis of electricity consumption.

A key implication of these outcomes in the current market environment is that other (non-DER) customers effectively 'pick up the tab' for DER customers through higher network charges than would be the case under LRMC-based structures. This is why implementing tariff structures that promote economic efficiency is at the core of our corporate strategy – our desire to address electricity affordability issues and allow us to provide the best possible price for all our customers.

The benefits of more efficient LRMC-based tariff structures are likely to be in the long-term interests of consumers. Adoption of efficient levels of electric vehicles, solar photovoltaic (PV), storage and energy management technologies in the right network areas would reverse the current trend, lowering customer bills through greater network utilisation.

5.2 Determining the peak period

Analysis of the set of load profiles was undertaken to identify the set of periods that best reflect the network peak demand period, once random and systematic factors were taken into account. This analysis delivered the set of periods that best reflected peak demand across Ergon Energy's ZSs.

Segmentation approach

ZSs were first grouped into mainly residential (MPR) and mainly business (MCI) segment datasets to develop the following six representative maximum and average daily 30 minute load profiles:

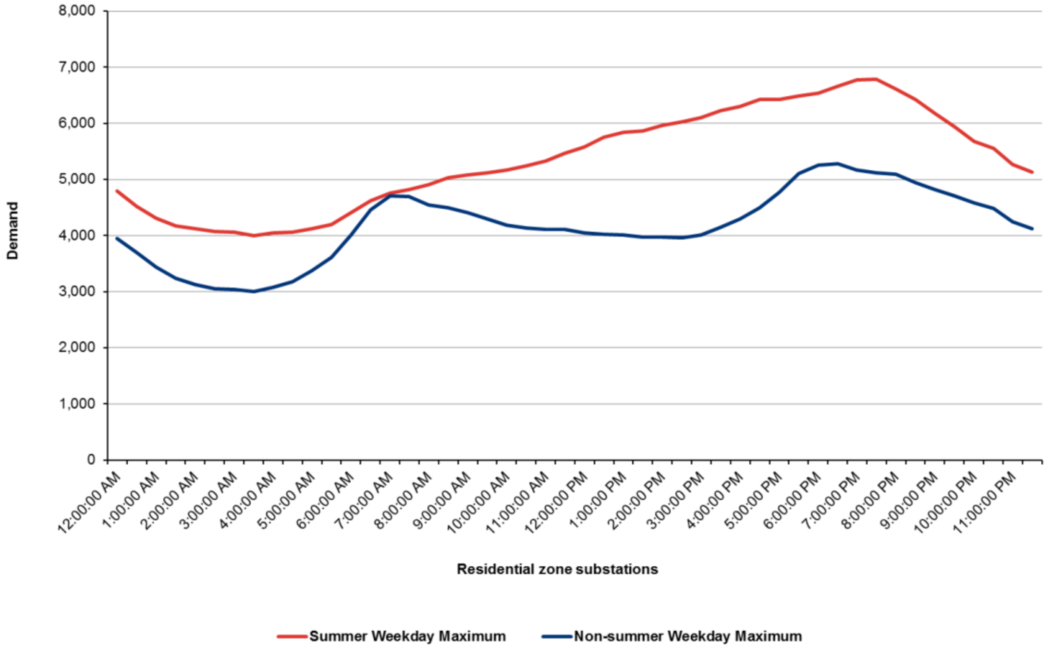
1. Summer season, weekday
2. Summer season, weekend
3. Winter season, weekday
4. Winter season, weekend
5. Shoulder season, weekday
6. Shoulder season, weekend.

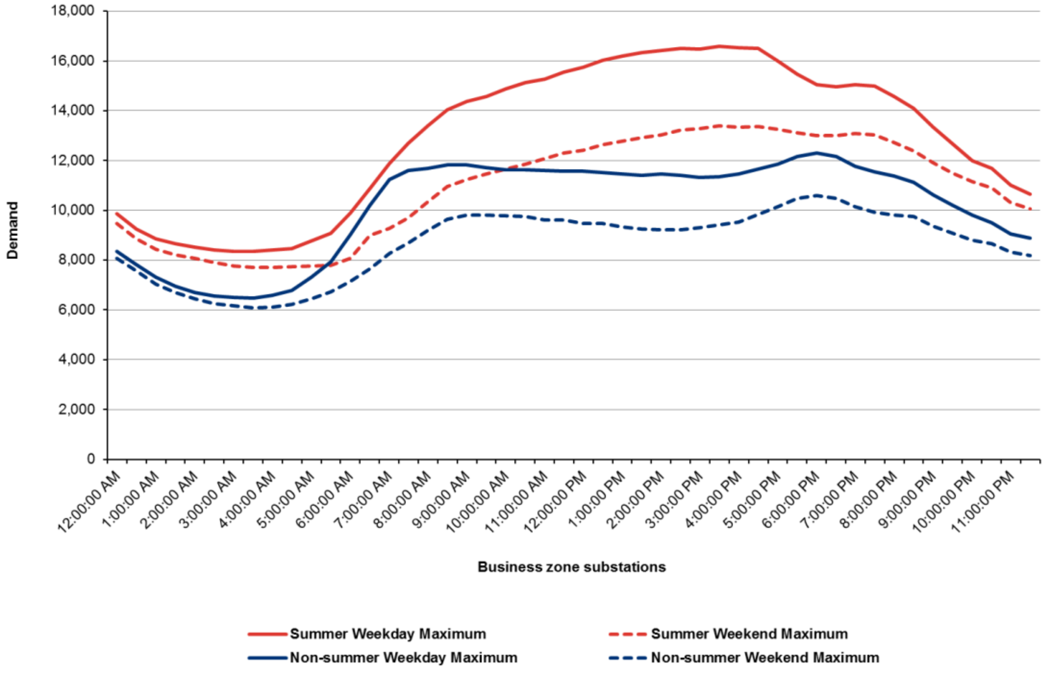
The average of the maximum hourly loads for each of the ZSs in the segment was calculated to identify the highest 30 minute intervals across all of the ZS profiles by season and weekday or weekend to estimate its likelihood of becoming a future global peak due to systematic factors such as price response (analysed and described further below) and to provide a ranking methodology for classifying the 30 minute interval between the peak and off-peak periods.

Aggregation approach

The ZS cost driver analysis methodology should be consistent with the cost structure of meeting incremental load growth. An average of the maximum 30 minute load approach was chosen as the fixed costs associated with ZS project and site establishment were understood to be relatively less significant than project variable costs, and the correlation of areas with relatively large loads to augment capacity using relatively larger ZSs.

The results of our peak demand profile development are shown in Figure 1. This approach to characterising peak demand reveals the zone wide timing and structure of annual peak demand. The relativities of seasonal and day type load profiles and the differences between mainly business or residential substations can also be seen. For example, the peak demand of mainly residential ZSs in the East Zone occurs around 8.00 pm, while mainly business ZSs peak demand occurs around 5.00 pm.





Source: Ergon Energy, Energeia

Figure 1: Maximum 30 minute demand by season, day and customer type (East Zone)

Classification approach

Residential ZS load segmentation highlights the significantly higher summer weekday and weekend periods compared to alternative seasons and day types. By separating out the summer period from the other periods, it enables a much more cost reflective seasonal time-of-use (TOU) structure to be defined. Adopting a daily TOU structure would not reflect the strongly seasonal pattern. Instead, it would flatten and extend the peak period, which would reduce the level of prices and demand response during the summer peak period.

Business ZS load segmentation shows a different overall profile of consumption, with a flatter peak period and a greater demand reduction due to day type. The summer weekend profile is significantly lower than the weekday profile. This analysis again supports the use of a seasonal weekday peak TOU structure to better target seasonality in peak demand.

Table 6: TOU periods for residential and business customers (East Zone)

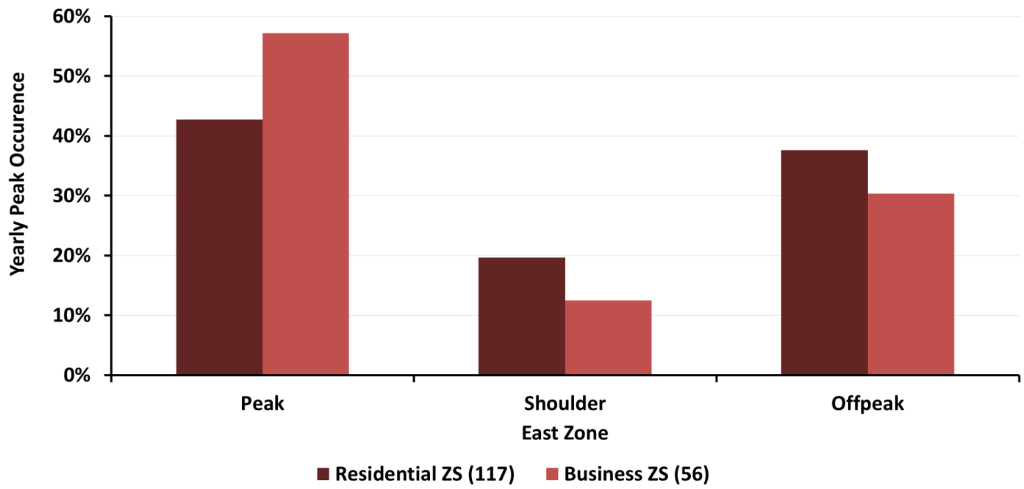
Peak	Times	% hours	% consumption
Residential customers			
Peak	3.00 pm to 9.30 pm on all summer days	6.7%	9.0%
Off-peak	All other times	93.2%	91.0%
Business customers			
Peak	10.00 am to 8.00 pm on summer weekdays	7.5%	10.2%
Off-Peak	All other times	92.6%	89.8%

Note: Summer is defined as December, January and February.

Validation approach

As with setting the seasonal peak period, it is important to correctly set the hourly peak period to avoid over- or under-signalling the cost of peak demand. Including hours that are unlikely to drive peak demand reduces the price per kWh and thereby the economic signal to loads operating in the period of peak demand.

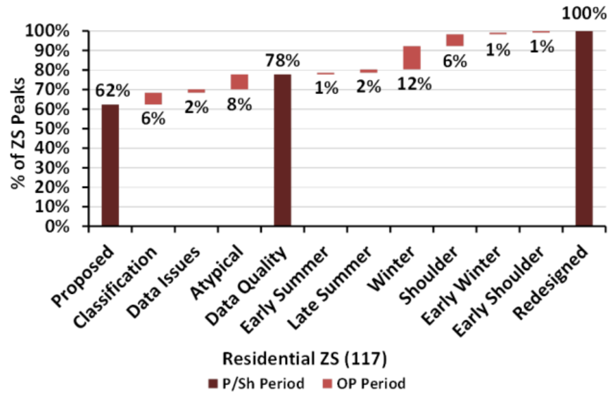
The definition of off-peak periods were therefore compared to the actual distribution of peak periods of the underlying set of residential ZS to assess the systemic risk of off-peak prices resulting in undesirable increases in peak demand growth. As peak prices are higher than the current any time price, the key risk is in the off-peak. Figure 2 presents the results of the analysis.

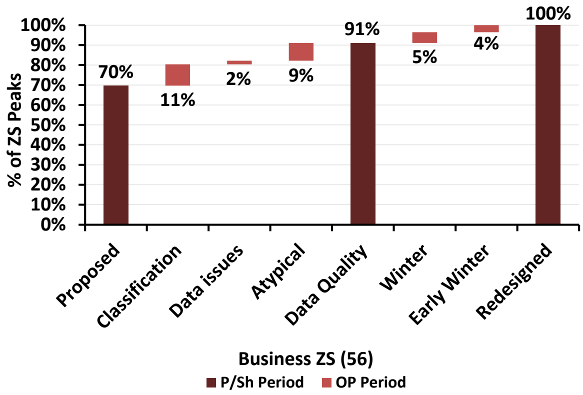


Source: Ergon Energy, Energeia

Figure 2: Distribution of ZS peaks across TOU period definitions by ZS type (East Zone)

The initial finding of around 30-40% of ZS peaks falling outside of the peak period was investigated to determine whether the time periods should be changed to better address ZS diversity. The results of the analysis are presented in Figure 3, which shows that about half of the variation and around 20% of total ZS variation might be addressed by changing the definition of the off-peak period. The rest of the variation appears due to data quality issues including incorrect classification and incorrect peaks in the data.





Source: Ergon Energy, Energeia

Figure 3: Drivers of variation in ZS loads (East Zone)

Energeia's analysis of the drivers of variation among residential ZSs in the East Zone found that the winter peak was the main factor, accounting for 12% of ZS in the group. However, adding a winter to the peak would reduce the pricing signal by around 50% for the remaining 80% of ZS loads, so this change was not pursued. As the other drivers represented a lower percentage of the total population, changes to the structure were less likely to be appropriate. A similar analysis of the commercial structure resulted in a similar conclusion to not modify the proposed tariff design.

5.3 Changing dynamics of the electricity network

Addressing electricity affordability is at the core of Ergon Energy's corporate strategy. Network tariff reforms are a key part of achieving this, but must be aligned with changes in consumer behaviour and response. New market participants and emerging technologies (i.e. distributed energy assets, control systems and end-user technologies at or near the customer's premises) are impacting and interacting with the distribution network in ways that have not been seen before at a national and global level.

In 2014, Ergon Energy's customer research found that 87% of customers in our network area have actively pursued and adopted energy efficiency measures to reduce their consumption and in turn their electricity bills. In addition 76% of customers either have, or intend to, pursue alternative energy solutions (e.g. rooftop solar) in order to reduce the size of their electricity bill.

We noted earlier that the lack of cost reflective prices driving distortions in customer behaviour results in significant and growing spare capacity for many network assets, while others are facing constraints due to high concentrations of inefficient residential and commercial rooftop solar PV investment.

On this basis, Ergon Energy believes the benefits of more efficient LRMC-based tariff structures are likely to be in the long-term interests of consumers.

6 Outcomes for each customer group

6.1 Inclusion of LRMC in tariff design

The first point that follows from the new pricing principles is that whether a tariff can be said to be "based on" LRMC is a matter of degree. As noted above, clause 6.18.5(f) of the NER provides that the manner of calculating and applying the LRMC to network tariffs is to be determined having regard to:

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

This suggests that for tariffs to comply with this clause, they would ideally (subject to calculation and implementation costs) incorporate components that varied by time and location. However, according to a report prepared by NERA, consultants for the AEMC, even a simple fixed and energy tariff can be described as being based on LRMC. This point is discussed further below in the context of recent modifications to Ergon Energy's legacy tariffs.

The second point is that the obligation on DNSPs to ensure tariffs are based on the LRMC is not an absolute one. The NER provides that a DNSP must consider the impact of tariff changes on retail customers and may set tariffs at variance from LRMC for a transitional period (which may extend beyond one regulatory control period) to the extent the DNSP considers this reasonably necessary having regard to:

- the desirability of tariffs complying with the pricing principles, including the need to reflect LRMC
- the extent to which retail customers can choose the tariff to which they are assigned
- the extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions.

The NER also provides that the structure of each tariff must be reasonably capable of being understood by retail customers assigned to that tariff. We have taken all of these considerations into account when applying LRMC to both our 'legacy' tariffs and our optional tariffs.

6.2 SAC Small

Legacy tariffs

In 2014-15, Ergon Energy commenced the process of restructuring our default SAC tariffs to better reflect the LRMC. Reforms to tariffs for this customer group have to date included moving from a simple fixed and energy tariff to an Inclining Block Tariff (IBT) to facilitate an increase in the fixed charge and a reduction in the average energy tariff in a way that helped to mitigate adverse customer impacts.

Our intention in the medium term is to gradually rebalance the IBT such that the first consumption block at least reflects the value of the LV LRMC, in the manner suggested in NERA's report for the AEMC (see Box 1).

For flat, inclining or declining block tariff, the minimum tariff (for the flat and for each block of the inclining or declining block tariff) can be calculated as follows:

$$\text{Minimum Flat, Block Tariff (\$/kWh)} = \text{Max}\left[\frac{LRMC of\ 1\ kVA}{8{,}760 \times AveragePower\,Factor}, \frac{AvoidedCostIfNoUsage}{TotalElectricityUse} \right]$$

Source: NERA (2014), *Economic Concepts for Pricing Electricity Network Services*, A Report for the Australian Energy Market Commission, 21 July 2014, p25.

Box 1: NERA proposed application of LRMC to IBTs

Assuming a LV LRMC of $378/kW p.a. and an assumed power factor of 0.9, this suggests that the average zone-weighted first consumption block should rise over time to approximately $0.048/kWh (being $378/[8,760*0.9]). This move should also encourage customers to shift to our optional STOUD tariff, which provides more efficient network usage signals (see below).

While Ergon Energy intends to phase out our legacy tariffs over time, the ongoing rebalancing of these tariffs in the manner described above will enable these tariffs to better reflect LRMC than they did previously.

Cost reflective tariffs

The SAC Small customer group exhibits the following characteristics:

- There is a clear difference in load profiles between residential and business customers.
- There is also sufficient segmentation (at least at the substation level) that reflects the differential in loads between residential and business customers. In other words our substations are largely residential-based or business-based.
- Customers within this customer group have substantial diversity between other loads and with the network peak loads. There is reasonable correlation between the day of individual peak demand and system peak demand but not a strong correlation between the individual's single half hour peak demand with the system peak demand.

Ergon Energy engaged Energeia to develop and compare alternative demand-based tariff structures for residential and small to medium business customers. Their observations for this customer segment were as follows:

- Tariffs which included a demand-based element generally performed better than IBT and TOU energy-based tariffs.
- Tariffs using more peak periods in the pricing mechanisms performed better than those tariffs using a single maximum demand period across both customer classes.
- Average Demand Tariffs tended to perform significantly better than Ergon Energy's TOU energy-based tariffs, largely because TOU energy-based tariffs are still dependent on volumes for recovery at off-peak times.

Ergon Energy developed tariffs which apply the LRMC to the average demand in a daily demand window because the Energeia analysis demonstrated this application provided the best outcomes for customers, the network and community.

In addition, Ergon Energy took into account simplicity and customer impacts of different scenarios. There are obvious customer impact issues associated with a single charge, which can disadvantage customers with a relatively high, once-off peak demand.

Because individual customer maximum demands are not heavily correlated to the timing of network utilisation peaks, applying an LRMC charge to one period in the month could penalise customers inefficiently for their individual maximum demand and provide no further incentive to reduce demand outside of this individual peak. Analysis by Energeia confirmed this, demonstrating the change in correlation of a customer's calculated peak demand with their ZS peak demand as the number of peak days included in the calculation was increased. Figure 4 demonstrates that, for residential customers, the peak charge chosen affects the level of correlation between the individual peak demand and the network peak demand.

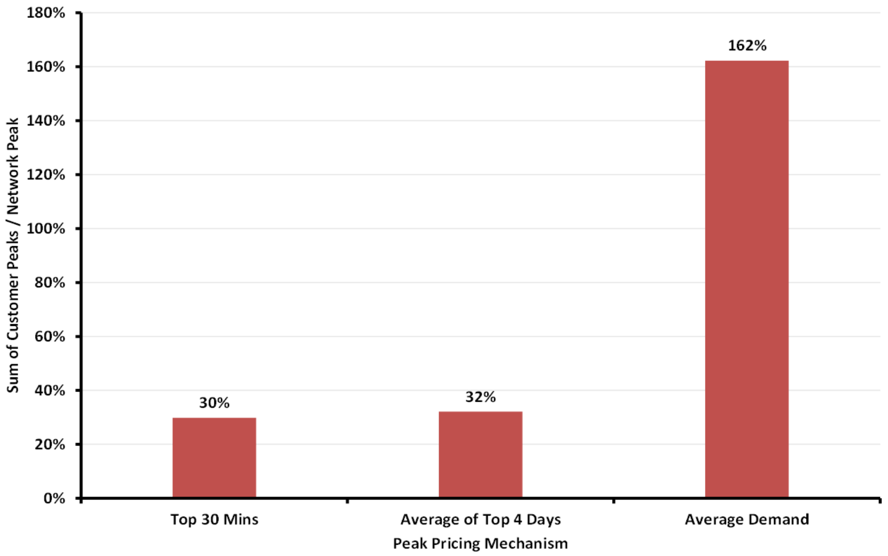


Figure 4: Drivers of variation in ZS loads (East Zone)

The use of the average of the highest four days of average demands (at the peak times) balanced the increase in correlation against the sharpness of the signal, which decreased with additional days. Ergon Energy found that by applying the LRMC to an average of demands over a smaller window, customers have more control over how they use their energy without being substantially impacted by an 'outlier' demand event. It also provides a signal to customers outside of their individual maximum demand, which again increases the benefits of aligning customer behaviour in the peak window to the network utilisation peak.

The level of scaling was determined by calculating the sum of all customers' peak demands during the peak period and dividing this by the total network peak for the class during the peak period. The results of the scaling for each of the customer classes are below.

Table 7: Scaling factor applied to top four averaged demand (specified times), residential and business

Customer class	Scaling factor applied
Residential	1.03
Business	1.28

Since 1 July 2014, SAC Small customers have also had access to a Seasonal Time-of-Use Energy (STOUE) tariff. The STOUE is structured with a fixed charge per day and an energy (volume) charge which includes seasonal and time-of-day dimensions. Analysis from Energeia suggests that TOU energy-based tariffs are inferior to demand-based tariffs in that they over-signal the LRMC across too many observation periods (all half hours in the peak period window). However, we recognise that the tariff has the support of some existing customers and consumer groups and therefore we have agreed to continue to include a STOUE for the remainder of the TSS period.

6.3 SAC Large

Legacy tariffs

Reforms to tariffs for this customer class have to date included increasing the daily fixed charge and reducing the actual demand (kW-based) charge. A key rationale for these changes was to provide signals for network usage more in accordance with the LRMC of servicing these customers.

Cost reflective tariffs

There is more uniformity of load profiles in this customer group compared to SAC Small customers and therefore the co-incidence of individual peak to system peak is much higher. The difference in the level of diversity between the individual maximum demand and the network maximum demand is demonstrated in the table below.[38]

Table 8: Scaling factor for SAC Small and Large

Customer class	Scaling factor for tariff based on monthly maximum demand
SAC Small Residential	0.40
SAC Small Business	0.67
SAC Large	0.76

There is also an existing peak demand charging mechanism in place, which customers have adapted to, and any transition towards a new charging mechanism will need to be appropriately managed.

For this reason we have adopted a different approach for SAC Large customers. Rather than the average demand as applied for the SAC Small customer group, we have instead applied the LRMC to the maximum monthly demand in the peak period window.

As noted above, the scaling factor is calculated at 0.76.

Given the tariffs for SAC Large customers are usually self-selecting, our preference would be, from July 2017, for new premises and customers moving into existing premises for this group (with the required metering) to be subject to this tariff (with the option of choosing the legacy demand tariffs if desired).

[38] This is determined by calculating the sum of all customers' peak demands during the peak period and dividing this by the total network peak for the class during the peak period.

6.4 CAC

Legacy tariffs

Like the SAC Large customer group, Connection Asset Customer (CAC) legacy tariffs incorporate some element of cost reflectivity. Recent changes to these tariffs include:

- introduction of kVA signalling for the demand charging components
- introduction of an excess reactive (kVAr) power charge for customers with a power factor that is outside NER criteria.

While there is little recognition of seasonal drivers of network investment in CAC legacy tariffs, we recognise that some CACs operate at higher levels of the network and may have more dedicated assets allocated to them. It is possible that there will be some customers who have such a strong proportional use of shared network infrastructure, the signal is less likely to be seasonal based (and more reflective of the customer's authorised demand). Nevertheless, we believe for the majority of customers in this customer group there will be beneficial network outcomes through a broad-based network LRMC signal.

Cost reflective tariffs

While recognising the cost reflectivity of the legacy tariff, we have included options for customers in this grouping to access a tariff which applies the LRMC to the summer month peak periods. Similar to SAC Large, the CAC STOUD tariff applies a LRMC demand charge, based on the monthly maximum demand during the peak period ($/kVA/month). This reflects the fact that these customers have a stronger correlation between individual maximum demand and network substation peak times.

6.5 ICC

The principal reason we have focused less on the application of LRMC to Individually Calculated Customers (ICCs) to date is that these customers tend to have less influence on the need for shared network investment than customers connected at lower voltages.

ICCs are different to other customers. For a given authorised demand, an ICC's actual demand (within the authorised demand) does not 'cause' the need for augmentation because the network must be developed to meet the agreed level of authorised demand.

However, where an ICC's actual demand exceeds its authorised demand, the ICC's 'excess' demand could contribute to LRMC. Therefore, it is appropriate for ICCs to pay an appropriate LRMC-based charge on such excess demand. The question is whether this excess demand charge should be equal to the customer's existing capacity charge or a different rate. This depends on whether the capacity charge is an accurate proxy for the LRMC that the customer's excess demand imposes on the network.

Therefore, in the absence of more customer-specific (e.g. perturbation) estimates of ICC LRMCs, it would be reasonable to suggest that ICCs should pay a charge on their excess demand that is the higher of their:

- voltage level LRMC ($/kVA), and
- capacity charge rate ($/kVA).

This will help ensure that ICCs who exceed their AD pay at least their voltage level LRMC rate.

Increasing or reducing authorised demand

We are exploring whether new ICCs, or ICCs increasing their authorised demand, should be required to pay a capacity charge reflecting their applicable voltage level LRMC. In our view, this slightly different treatment may be appropriate as it embodies a potential penalty to discourage the ICC from avoiding increasing its authorised demand.

ICCs sometimes apply to reduce their authorised demand. Presently, they do not avoid their fixed connection charges in doing so, but they may reduce their contribution to shared network costs via their capacity charge and actual demand charge even though the reduction will do little to reduce Ergon Energy's avoidable costs (as these costs are largely sunk).

Ideally, ICCs that seek to reduce their authorised demand should not be permitted to do so, at least unless the reduction can be shown to avoid future costs (through a perturbation or similar LRMC estimate). If this approach is not considered feasible, we propose that ICCs seeking to reduce their authorised demand should receive a capacity charge reduction in relation to their reduced authorised demand that is based on the lower of their:

- voltage-based LRMC ($/kVA), and
- capacity charge rate ($/kVA).

This will help ensure that ICCs who reduce their authorised demand avoid charges of no more than their voltage level LRMC rate.

We do not propose to fast track any ICC tariff structure changes to those applied in 2015-16 prices. However, we will consult on some of these options for the next regulatory control period 2020-25.

Appendix C Excess kVAr Development for ICCs and CACs

This appendix sets out additional information on our excess reactive power charge for Individually Calculated Customers, including details of our consultation with Connection Asset Customers. The AER encouraged us to include this information in our revised TSS as part of its draft decision.

Background to kVA and excess kVAr charging customer consultation

Ergon Energy started its review of network tariffs in 2012.

For Individually Calculated Customers (ICC) and Connection Asset Customers (CAC), a fundamental weakness in the tariffs at that time was the denomination of demand components of the tariff in kilowatts (kWs). This was out of step with industry norms and also resulted in an inefficient and non-cost reflective tariff signal being communicated to our largest customers (accounting for 40% of our network consumption).

kVA tariffs have been adopted almost universally by the industry for large customers because network capacity requirements are determined by Total power (kVA) demand not Real power (kW) demand.

Effectively a tariff denominated in kW does not provide a financial incentive for customers to improve their power factor and results in a bias to customers accepting low and sometimes non-compliant power factors which has no tariff cost to the customer but results in Ergon Energy having to provide additional capacity to those customers and incurring the cost of doing so.

Interestingly, since the introduction of the kVA charging we have become aware of anecdotal instances of customers reactivating existing power factor correction equipment that they had but were not using.

Customer acceptance of kVA demand tariffs has progressed very smoothly, as typically these large customers saw the change as a move to broadly applied industry norms. We supported our customers through the change and responded to feedback where improvements could be made.

Excess kVAr charge

Our tariff development strategy for the ICC and CAC customers quickly evolved to adopt two mechanisms to signal the cost to the network of supplying the Total power capacity requirements of poor power factor customers. The first change was to kVA demand and the second was the introduction of excess kVAr charging. Excess kVAr charging was at that time deployed in South Australia and was being explored in the Northern Territory. In South Australia it had been successful in incentivising many customers with non-compliant factors to carry out the necessary changes to become power factor compliant. Customer response was driven by both the transparency the charge brought to non-compliance and the financial incentives it provided to undertake corrective action.

The excess kVAr charge is only most likely activated when a customer has a non-compliant power factor. S5.3.5 Power factor requirements in the NER specifies compliance requirements by voltage level. There are complementary obligations in the *Electricity Regulation 2006* (Qld). For most customers excess kVAr charges will not impact their costs. The way excess kVAr charges apply is that each customer has a ‘permissible kVAr quantity’ calculated based on their authorised demand and the compliant power factor applicable at their supply voltage. The permissible quantity represents the kVArs the customer has implicitly paid for in their demand charges. When determining whether a monthly excess kVAr charge is applicable or not, the kVArs consumed in the customer's peak monthly half hour kVA demand is compared with the permissible quantity and if higher than the permissible quantity, the charge is applied to the amount greater than the permissible quantity.

kVA and excess kVAr Implementation

For the introduction of both the kVA and kVAr charges, the implementation strategy was to introduce the change to the ICC customers first and then to the CAC customers the following year. Our intent and implementation strategy was advised (by letter) to all CAC customers on 5 December 2014 together with a brochure describing the operation of kVA and kVAr charges.

The implementation timetable advised was:

Customer Class	kVA denomination of demand	Excess kVAr charges
ICC	2014-15	2015-16
CAC	2015-16	2016-17

This cascaded approach to implementation was adopted because it provided a longer lead-time for CAC customers to adjust and participate in the consultation phase and also provided more time for other stakeholders and ourselves to work through the implementation process with the ICC customers before extending the change to the CAC customers.

We recognised that while the change to kVA tariffs aligned with what these customers and their advisors and retailers were familiar with, the excess kVAr charge would be new to a number of them.

Development of the Excess kVAr charging mechanism for ICC customers

The mechanism described above to determine the permissible kVAr quantity was not our original mechanism for charging for excess kVAr. The original approach had a mechanism that meant operation outside of compliant power factor at the monthly peak kVA interval could be charged for the excess kVArs occurring based on their demand at that time. Following consultation and representations from customers who submitted that this approach meant they were potentially being charged for a level of kVAr use that was less than what they were entitled to when power factor compliant at authorised demand, the approach outlined above was adopted.

Implementation of the excess kVAr charge for ICCs has gone smoothly. However, following this change, a review of 2015 June and July billing for excess kVAr charges uncovered a previously unidentified issue for customers with both load side and generation which is discussed below.

kVA/kVAr Adjustment Where Load and Generation is Combined

When customers with both load side and generation record generator kVAr on start-up and shut down (thus contributing significantly to the lagging load kVAr), this results in increased load charges from DUOS and TUOS kVA and DUOS excess kVAr demand quantities. This is an inadvertent side effect of the change to-kVA billing and the relevant metering registers being impacted by both generation and load activity.

There are a number of generator/load combinations within Ergon Energy's system (22 CAC customers and 3 ICC customers) and the review of the impact of embedded generators on load side network charges included Embedded Generators (EGs) with CAC and ICC load side classification. Not all customers' load charges were affected by the presence of the generator and for some the impact was not significant. However, there were a number for whom the impact of increased network charges could be material.

The outcome of the review was to recommend that to avoid a situation where the generator reactive power output affects the load reactive power demand, for the purpose of network charging, the lagging kVAr should be set to zero in any interval where the generator is enabling energy to be imported to the network. This results in reduction of the kVA and kVAr charging components for the load. Energex currently adopts this approach.

The above business rule was adopted from 1 July 2016.

CAC Excess kVAr Consultation

The CAC consultation has taken place in the context of an extensive consultation initiative that commenced in September 2012 where we engaged Ernst & Young to undertake generic tariff research, talk with key regional Queensland stakeholder groups and prepare independent tariff reports that would provide a knowledge foundation on which stakeholders and customers could contribute to Ergon Energy's network tariff strategy consultation process.

The Ernst & Young documents were part of the collateral provided to support the initial commencement of the formal network tariff consultation process where we sought involvement from all interested stakeholders in the development of our network tariff development strategy.

The core commencement document in this process was Network Strategy Review – Consultation Paper (dated 27June 2013). This document and the subsequent formal consultation papers and customer responses can be tracked through our website on link https://www.ergon.com.au/network/network-management/network-pricing/network-tariff-strategy-consultation/past-consultation-information

To maximise awareness and the opportunity for stakeholders who may want to participate in our tariff development journey, this consultation was extensively promoted through a number of channels including newspapers throughout Queensland, our website, direct advice to our large (CAC and ICC customers), Ergon Energy's existing stakeholder networks and through the Queensland Competition Authority's notified price consultation mailing lists and network.

Our 'Network Tariff Reform Report - Network Tariff Reforms 2015-16- Tariff Structure Statement 2016-20 - June 2015' (Attachment 1) provides a good recent consultation history/current status and tariff intentions in the context of the full scope of the consultation undertaken across all customer segments. Each phase of consultation typically involved the opportunity for customers to formally respond to the consultation papers, participate in briefing sessions and some customers/representative groups would take up issues directly with Ergon Energy.

Within this holistic consultation where significant change was occurring across all our tariffs, the following maps some key timeline activities with ICC and CAC customers related to the introduction of Excess kVAr charges.

- kVAr to ICCs in customer brochure 10 April 2014.
- kVAr for CAC in 2016-17 detailed in the Consultation Paper Network Tariffs 2015-16 on 5 December 2014 and in the stakeholder presentation pack dated 16 January 2015. At this time we were promoting distribution of our brochure 'Understanding kVA and kVAr Charges for Major Customers'.

- In February 2015 we received a number of responses from CACs or representative groups with respect to excess kVAr. Charges.
- Webinar on 18 March 2015 for ICC /CACs.
- Network tariff guide for plus 4 GWhs 30 March 2015 outlines the excess kVAr charge coming up.

In parallel to this activity available to stakeholders on the web, we have also been active in communicating directly with ICC and CAC customers with respect to the changes being proposed and the opportunity to provide input into the tariff reform process.

We note in particular the letter sent to all ICC and CAC customers dated 5 December 2014 advising of the excess kVAr proposal and providing a copy of the brochure 'Understanding kVA and kVAr Charges for Major Customers'.

Recent Consultation - post July 2015

During 2015 engagement with customers and stakeholders began to focus on the 2016-17 year and the 2017-20 TSS. Inclusion of changes in 2016-17 which were part of the tariff reform program going through to 2017 provided the contextual background for the 2017-2020 TSS i.e. we had to provide the linkage of 2016-17 between where tariffs were in 2015-16 and where they would be on 30 June 2017. The change to excess kVAr for CACs was part of showing the continuity and was incorporated into the advice regarding changes for 2016-17 as part of TSS consultation undertaken in July 2015.

In November as a preview to submission of our TSS we conducted a webinar and published on our website our 2016-17 plans which included CACs.

Following release of the AER Issues paper on Ergon Energy's TSS we held another webinar in early April 2016 which again included in the presented and published slides the change to excess kVAr charges for CAC customers in 2016-17.

We have continued to ensure customer and retailer awareness and readiness for excess kVAr changes and the other 2016-17 changes. On 12 May following submission of the 2016-17 Pricing Proposal we held a webinar for each of our three major customer segments. These were all well attended and have also been published on the web.

Deferral of Introduction of the Excess kVAr charge for CAC Customers

In response to submissions by two customers regarding our TSS, the AER requested implementation of the Excess kVAr charge for CAC customers be deferred until after the TSS Consultation process was complete. Customer concerns raised were that the charge was: (a) not cost reflective (b) disadvantaged customers with generators (c) should only apply at system demand periods; and (d) should not apply to single events. The AER sought further submissions.

In summary our responses to the issues are:

- The rate for the Excess kVAr charge was set so as to provide sufficient incentive for the customer to correct their power factor. That is the cost it reflects. It is designed to provide an appropriate incentive for the customer to meet its obligations under the NER and the *Electricity Regulation 2006* (QLD).
- A customer that is compliant with the required standards and operating within their Authorised Demand will not be charged Excess kVAr.
- The billing of the charge has been refined to ensure it will not disadvantage customers that have an embedded generator, in two ways:

- The generator will not contribute to the load kVAr, as Ergon Energy now charges load kVA = kW for any interval where there is generation; and
- The Authorised Demand kVA at compliant power factor has now been adopted as the maximum kVAr to apply at all lower demands. kVAr in excess of this are chargeable. In effect, this permits lower than compliant power factors at demands lower than that authorised.

- With regard to charging for single events, like all other network demand charges it applies to the peak half hourly registration at time of maximum demand on the network. There is no justification for a different approach to be applied to this particular charging component.
- Network charges cannot be aligned with system peak, other than through the nomination of daily peak periods during which the peak is likely to occur. To do otherwise would require knowledge of, and communication of the peak charging period to the customer in advance, this is currently not practicable without significant additional infrastructure and potentially would simply result in peak shifting.

Appendix D Additional information in response to AER Draft Decision

In August the AER released its Draft Decision with respect to our TSS.

In the discussion supporting the AER's intention to approve our TSS, the AER identified a number of areas where it suggested that we may like to provide further comment in the revised TSS. The draft decision also provided commentary on aspects of our submission. We have consolidated our responses to these issues in this section.

Issue	AER comment	Ergon Energy response
Interaction with network planning and demand management	While not explicitly required of distributors by the Rules, we consider it useful for tariff statements to describe the distributor's approach to integrating tariff reform, network investment and demand management. Such discussion will position tariff statements within the broader context of how distributors intend to respond to demand and service challenges. Also, while the Rules require distributors to consider the time and location varying nature of network cost drivers, difficulties with locational pricing suggest a larger role for demand management initiatives to address local network demand pressures.	Cost reflective tariffs create the bridge between network planning and the customer by providing transparency to the customer of what customer behaviours are driving our network augmentation expenditure. As developed in our TSS, our approach to setting network tariffs will increasingly utilise LRMC as the foundation building block to set the rate of the peak demand charge component. This will mean network tariffs will reflect the average LRMC within a pricing zone level over the long run. In practice, differences between the average system LRMC incorporated in network tariffs and localised higher LRMC associated with points of actual network capacity constraint at a particular point in time will arise. Ergon Energy considers responding to localised capacity constraints is most efficiently addressed through dynamic demand management initiatives that can be accurately targeted, calibrated at the known opportunity value, and specifically harmonised in terms of time, location, structure and price. Complementing standard tariffs with demand management initiatives allows Ergon Energy to both signal average LRMC while also overlaying a tightly targeted additional value signal in constrained areas to facilitate Ergon Energy optimising our asset investment and timing. The benefit from the optimisation that is enabled and the savings from deferred or avoided capital investment flows through to all customers, not just those in the constrained area. We see this approach as integrating network planning. Used effectively the publication of incentives for customers to reduce demand at

Issue	AER comment	Ergon Energy response
		specified locations and at specific times is a useful proxy for critical peak pricing and real time pricing. The following links show examples of 'incentive maps' in the constrained areas of South Mackay and Cannonvale: https://www.ergon.com.au/network/manage-your-energy/incentives/cannonvale-incentives/eligibleareas https://www.ergon.com.au/network/manage-your-energy/incentives/mackay-incentives/eligible-areas. Network risk is monitored and assessed on a seasonal basis. The rates shown are adjusted as network risk varies. Ergon Energy is also working with a broader demand management opportunity presentation initiative being progressed on a national basis: http://nationalmap.gov.au/renewables/. The potential tension between standard network tariffs and constraint based locational prices is being addressed by overlaying cost reflective LRMC network tariff signals with specific demand management initiatives that are independent of, but built on the network tariff price signals. Our demand management initiatives in Townsville, Mackay and Hervey Bay are examples of the dynamic layer in practice, where locational network value over and above what is reflected in the tariffs is made explicit to the market.
Tariff assignment policies (opt in - opt out)	The approach adopted by Energex and Ergon Energy is the least progressive of the possible approaches. With appropriate metering becoming more widespread and tariff reform under way, for subsequent tariff statement proposals stakeholders should expect that distributors, may propose more ambitious changes to tariff assignment to cost reflective tariffs.	Our TSS did advise we may seek to apply the STOUD to all new premises connections (with installed metering capable of applying the tariff) on an opt-out basis from 1 July 2018 for SAC Small. For SAC Large our preference was that from 1 July 2017, for new premises and customers moving into existing premises (with required metering) the STOUD tariff would apply (with the customer having the option of choosing the general demand tariffs if desired). While a final position on this will be dependent on resolution of a number of uncertainties with respect to market readiness and aligned with the Power of Choice initiative, which is aimed at making smart meters available to customers

Issue	AER comment	Ergon Energy response
		with meter supply on a competitive basis, we interpret AER's comments as being supportive of adopting the opt out positions as foreshadowed in the TSS. For clarity we note that for CAC our position is that the default tariff for all new customers is the STOUD tariff (on an opt-out basis). This recognises the sophistication of these customers with respect to purchasing energy and their access to meter data and demand forecasts.
SAC Small inclining block	We encourage Ergon Energy to reconsider its current default inclining block tariff in subsequent tariff statements proposals as customers adopt smart meters	Refer comments above.
SAC Small STOUD - customer demand averaging approach.	We note Ergon's averaging approach may have the advantage of incentivising customers to minimise their peak demand throughout the billing period. The Australian PV Institute saw this as worthwhile for reducing bill shock but that it does not make the tariff any more cost reflective. The averaging approach may also dilute the price signal, undermining the intent of the demand charge.	We do not agree that the average of the top four daily peak windows does not make the tariff more cost reflective. We think the conclusions may have come about as a result of application of NSW based customer load profiles (with significant winter peaking) and misinterpreting of the off-peak demand charge as an LRMC charge (where-as it is part of our residual recovery). The recovery of the LRMC only over the period where the network is likely to be peaking (specified by season, days and time) aligns with the Australian PV Institute (APVI) view that the charge should be active only when the system is peaking and not to irrelevant customer maximum demands. The long peak period window also aligns with APVI preference. To the extent that an individual customer's maximum chargeable demand values correlates with maximum demand on the local network assets supplying that customer, basing the customer demand on their individual top 4 demand days also provides a mechanism to align the chargeable demand quantity with the peak demand of the local assets supplying the customer.. For example by using the top four summer maximum demand days, the tariff allows a Cairns customers tariff to be based on demands on the days the Cairns network is peaking, while for a Maryborough customer, the tariff correlates with (different) days when the Maryborough network is peaking. As part of our response to the AER comment regarding the ongoing need for customer education and support, we are developing a paper to provide more

Issue	AER comment	Ergon Energy response
		explanation of the attributes and features of the structure we have developed for the STOUD tariff.
SAC small STOUD - 3kW minimum demand	In principle, we do not object to Ergon Energy's proposal to set a minimum demand level for the demand charge. The effect is similar to a fixed charge. Customers are unable to avoid the charge. We are concerned that the level of Ergon Energy's minimum demand may be close to inefficiently penalising low demand customers.	If the off-peak demand charge had been part of our LRMC charge, we agree that a minimum demand charge is likely to be distortionary and inefficient. The off-peak demand charge is however part of our residual recovery and has been designed to work with the volume charge to recover residual revenue only. In evaluating this mechanism, several considerations led us to prefer this approach. The 3kW minimum demand does mimic a fixed charge, but with a number of advantages; it recovers the 'fixed' charge in the nine non-summer months resulting in a smoothing of the cash flow implications of a seasonal peak demand tariff on the customer network charges; it provides customers with an off-peak demand allowance of 3kW before they effectively start to pay any incremental off-peak demand charges which we see as progressive as most residential customers do not exceed the 3kW (as we measure it across the long demand window) and exceeding 3kW is seen as a proxy for' willingness to pay' residual. We also note the implied fixed charge on the STOUD tariff is circa $100 less than the alternative (IBT) tariff fixed charge. We therefore consider the mechanism when taken in its totality is beneficial to low off peak demand customers and note that if we had an explicit fixed charge, low off-peak demand customers would be paying both the fixed charge and an off-peak demand charge.
Excess reactive power charge	In response to submissions we did not approve Ergon Energy's proposal to introduce the excess reactive power charge to its Connection Asset Customers tariff class in 2016-17, as part of its annual tariff proposal. Ergon Energy submitted additional information to us regarding its excess reactive power charge for	We have set out this information in Appendix C. While we delayed introduction of the Excess kVAr charge for CAC customers in 2016-17 at the AER's request so as to allow finalisation of the TSS consultation activity. Our intention is that the Excess kVAr charge will be included in 2017-18 CAC tariffs. The charge will incorporate the changes outlined in Appendix C to address customer feedback.

Issue	AER comment	Ergon Energy response
	Individually Calculated customers, including details of its consultation with Connection Asset Customers prior to its planned introduction to that tariff class. We encourage Ergon Energy to include these details it its revised tariff structure statement.	
Large customer tariff charging windows (irrigation customers)	We encourage Ergon Energy to liaise with irrigation customers on this issue and consider the potential for more discreet tariffs that target irrigators' demands in future tariff structure statement period. It would be worthwhile if Ergon Energy could use its revised tariff structure statement for 2017-20 to respond to this issue, including whether it sees irrigators' connection characteristics and load profile as being sufficiently different to accommodate its own tariff class.	We have been asked to consider the potential for more discrete tariffs that target irrigators' demand in future tariff structure statement periods. Our initial review of this concept is that it is problematic to develop tariffs based on a specific sub-class of non-residential customers' connection characteristics and load profile. Underpinning our approach to tariff structures is that the LRMC is presented to customers at times when additional load is most likely to drive higher local peaks leading to new investment and higher future network costs. The structure is not designed around the characteristics of any particular customer segments load. Through our STOUD tariff structures we are presenting the opportunity for all customers to have visibility of our cost drivers and what avoiding presenting load to the network at those times is worth in the long term to the network. This provides the opportunity for the customer to choose to incur the peak charge or to change behaviour during peak times to avoid or reduce the cost. This mechanism works through alignment of our costs with the customer's behavioural choices through the tariff. If we were to structure the tariff around the capacity of a particular customer segment or sub-segment to avoid paying components of the tariff and not our own cost structure, we would be breaking the nexus underpinning cost reflective tariffs. It would also be very difficult for us to argue in our TSS that such tariff structures were cost reflective. We would also anticipate that other stakeholder groups would have a keen interest in this type of outcome emerging because if we presented tariffs that allow one customer segment to pay less than cost-reflective rates, then clearly others will be paying more. If the principle was then extended to all sub-segments, potentially no tariffs would be recovering peak charges. The mechanism through which load characteristics which are lower cost to serve can now be accessed is through the new STOUD tariff structures. We think these

Issue	AER comment	Ergon Energy response
		new structures now offer the opportunity for those customers with existing characteristics that are a lower cost to supply or have the ability to respond to the more granular and transparent cost signals to benefit from those characteristics. Even if the concept of end-use tariffs for segments of the non-residential customers was aligned with the pricing principles, a number of practical considerations arise in developing a tariff for an end-user based on a particular customer segments load profile. One of the key enablers would in our opinion be the need to not only demonstrate that the sub-segment was different to other sub-segments, but also that the customers in the sub-segment were highly homogenous. Through our discussions with Canegrowers and their many submissions with respect to tariff development, our understanding is that irrigation load is heterogeneous and subject to a greater range of variations than most load. Variation being driven by irrigation technology and operating regimes, weather, location, water availability, price of the growers output, industry etc. Even the same customer can present very differently on a year on year basis. We understand that the AER was suggesting that optional location specific pricing that target particular irrigation types will be feasible in future tariff structure periods. The non-homogenous nature of the loads would drive a multiplicity of irrigation tariffs. Additionally, in establishing a new tariff class, we would expect that not only the structure would be considered, but also the costs that need to be recovered. Typically network costs associated with low customer density and non-urban locations result in higher than average costs. As requested by the AER, we will undertake further consideration of end-use based tariffs and continue to engage with all stakeholders regarding the merits of this suggestion in development of our next TSS.
Calculation and	Ergon Energy is encouraged to respond to this	Optionality of tariffs as currently offered is a feature of tariff transition as we move

Issue	AER comment	Ergon Energy response
recovery of LRMC (irrigation customers)	(Canegrowers) material in its revised tariff structure statement. In particular, it should consider whether optional location specific pricing that target particular irrigation types will be feasible in future tariff structure statement periods.	from non-cost reflective legacy tariffs to new cost reflective structures. Providing tariff options is to provide time for customer adjustment, limit annual customer bill impacts and accommodate operational limitations such as suitable metering availability. Once transition is complete we do not envisage a scenario where multiple cost reflective tariffs can be presented to the same customer, particularly should the tariff options result in significantly different cost outcomes to the customer. We consider that there will be one cost reflective tariff offered to the customer. To the extent that a customer can adopt an optional non-cost reflective tariff and pay less, other customers will be required to subsidise that customer. We question whether a tariff reform end-state that provides a customer the opportunity to 'shop' between alternative networks tariffs that have a material difference in what the customer pays could be considered compliant with the pricing principles.

Appendix E Changes between the initial and revised TSS

This appendix identifies the changes that have been made to the TSS submitted on 27 November 2015.

The most significant change has been a major restructure of the TSS document and its appendices into two separate documents. This was done at the request of the AER to separate the compliance elements of the TSS from the supporting documents. Subsequent to this restructure, the following changes have been made from the original submission.

Change	Relevant TSS section
Changes advised through the draft decision process	
• *update prices and relevant figures (e.g. avoidable and stand alone costs) to reflect those approved by us in its 2016-17 pricing proposal and make associated amendments to future year figures*	Revised TSS: Section 7, Appendix A, B & C Supporting Information – Revised TSS: Appendix B
• *update sections on alternative control services to reflect any changes approved by us in the 2016-17 pricing proposal not already covered in the tariff statement and to reflect input received from us in March 2016 on the calculation of alternative control service prices*	Revised TSS: Chapters 10 and 11
• *update the tariff and tariff class reassignment procedures for standard control services to reflect new processes and contact details for the Joint Market Transaction Centre, which came into effect in March 2016[2]*	Revised TSS: Appendix D & E
• *remove references to the information guide for alternative control services, which will no longer be published from 1 July 2016[3]*	Revised TSS: minor updates throughout
• *correct typographical errors or ambiguous statements (if any)*	Revised TSS: minor updates throughout
• *update of long run marginal cost estimates to reflect outcomes of our final revenue determination*	Revised TSS: Section 6.3 Supporting Information – Revised TSS: Appendix B
• *reflect the current status of the proposed demand controlled tariffs which will not be introduced in 2016-17*	Our initial TSS referenced a new Demand Controlled tariff. The intention was that this tariff applies where a customer has agreed for load to be actively controlled by Ergon Energy to reduce demand at system peaks while not impacting on a customer's utility, at the absolute discretion of Ergon Energy. The tariff was to support products such as PeakSmart air-conditioning

Change	Relevant TSS section
	We had expected that this new tariff would have been introduced in 2016-17. As this tariff links to availability of associated load control products being available in the market that align with the calibration of the tariff, this new tariff was not introduced in 2016-17. The rates for this secondary tariff take into account the network benefit associated with the reduced contribution to peak demand. We still want to deploy an off-peak tariff that complements our STOUD tariffs. The timing of the deployment of this tariff does link with associated load control initiatives. At this time we would like to foreshadow that our preference is to align with our 2016-17 Pricing Proposal and continue not to publish the demand controlled tariffs in our Pricing Proposal until the supporting customer initiatives are in place to avoid possible confusion and unnecessary complexity for both retailers and customers. Section 5.3 of our TSS has been amended to clarify the tariff is not yet available
• *reflect inclusion of recovery of the energy industry levy in jurisdictional scheme charges*	Revised TSS: Chapter 4
• *provide further detail on the calculation of kVA and kVAr demand*	Supporting Information – Revised TSS: a new appendix (Appendix C) has been included
• *updates to reflect deferral of introduction of excess kVAr demand charge to Connection Asset Customers*	Minor amendments have been made to Section 5.6 of the Revised TSS. Also refer to comments noted against the excess reactive power charge issue in Appendix D
Changes identified through the 2016-17 Pricing Proposal	
• *clarify that the service 'customer requested appointments' has been broadened to include retailers*	Revised TSS: Section 10.3
• *minor changes to the service 'provision of services for approved unmetered supplies'*	Revised TSS: Section 10.3
• *broaden application of the service 'annual metering charges' beyond solar PV to be technology neutral*	Revised TSS: Section 10.4
• *possible minor change to service 'alternate supplies*	Revised TSS: Section 5.5.3 and 5.6.3 have been added to highlight that we are considering establishing a more cost reflective charging arrangement where SAC Large customers and CACs request an alternate supply (more

Change	Relevant TSS section
	than one connection to the network). Changes will not proceed as part of this TSS, but we are looking to undertake further analysis and consultation with a view to establishing any new tariff structures (if required) in the next regulatory control period 2020-25.
• *any other inconsistencies between the tariff statement and Ergon Energy's approved 2016-17 pricing proposal.*	Revised TSS: • Chapter 4 - network user definitions have been updated to reflect those approved by the AER in the 2016-17 pricing proposal • Section 5.6 has been updated to clarify the correct application of the Capacity charge for CAC tariffs. • The section in our initial TSS relating to the potential tariff for certain micro-embedded generators has been removed, given the AER approval of associated network user definitions. However, Ergon Energy anticipates that new (standardised) tariffs for EGs may still be required in 2017-20, in light of the increasing volume of micro-embedded generators connecting to our network. The tariff is of a similar nature to what was originally outlined in our initial TSS, and to the tariffs that are currently available for EGs. Section 5.8 of our Revised TSS outlines further detail • Section 5.8 has been added to clarify the new rules which apply for EGs who are also classified as an ICC (or CAC) for load connection. From 2016-17, for the purpose of network billing for loads, we will set export kVAr to zero in any interval when kW are imported in to our distribution network • Section 10.5 has been updated to reflect definitions of major and minor public lights included in our 2016-17 Pricing Proposal

In addition to the above, the following has been added to our TSS submission:

- Appendix D - to address specific issues arising out of the AER's draft decision
- A summary of our TSS has also been provided in Part B of this document, as per the AER's request

Ergon Energy Corporation Limited ABN 50 087 646 062

ergon.com.au