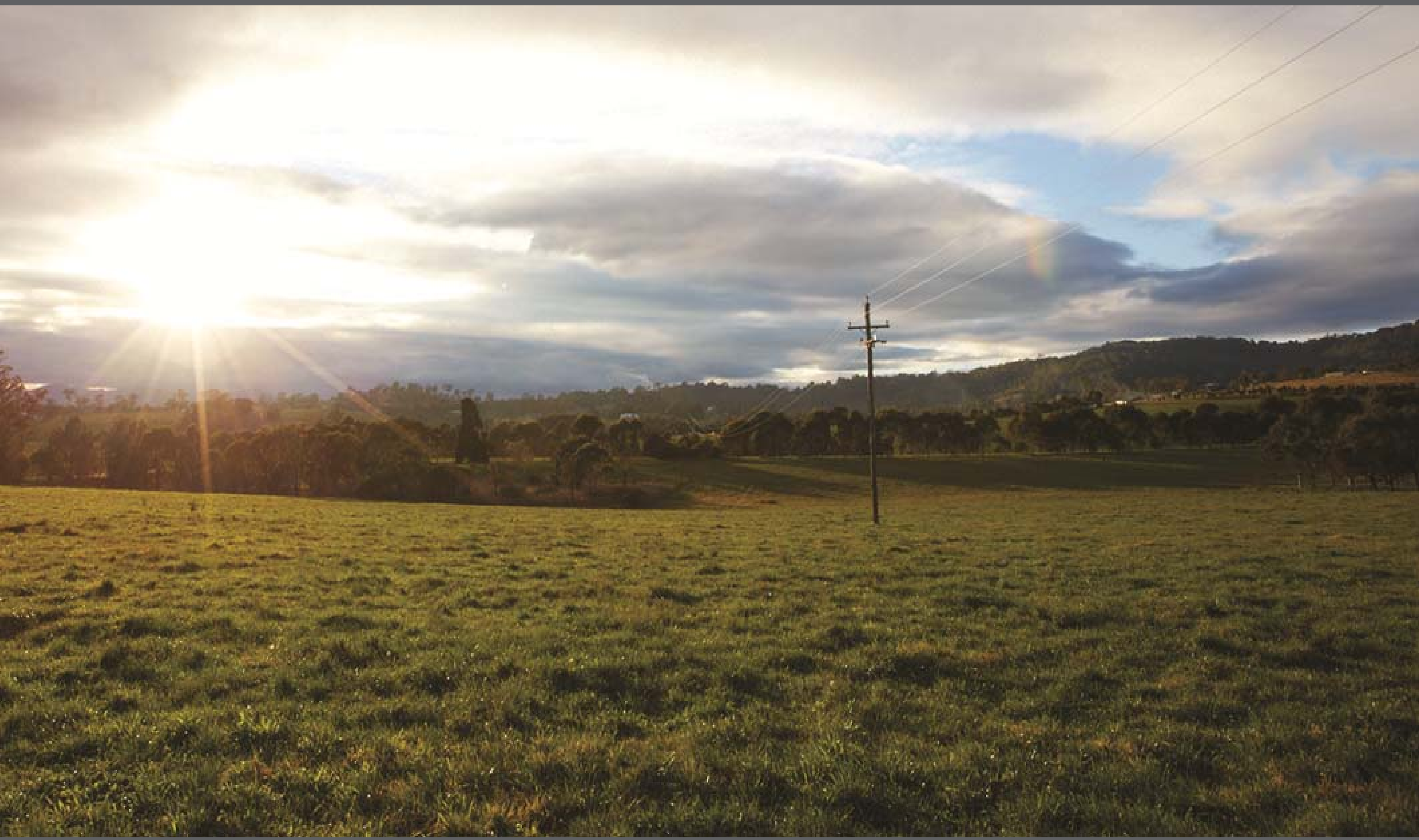
TARIFF STRUCTURE STATEMENT



Your power, your say

27 November 2015

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DISCLAIMER

GLOSSARY

Term	Meaning
2014-19 Determination	Our current regulatory control period running from 1 July 2014 through to 30 June 2019.
AEMC	Australian Energy Market Commission – the rule makers for Australian electricity and gas markets.
AER	Australian Energy Regulator – the national regulator that oversees the electricity industry.
Alternative Control Services	These are specific user requested services. They comprise: *Public Lighting*; *Type 5 & 6 Metering* (generally residential and small business customer meters); and *Ancillary Network Services*.
Charging parameters	The specific charge characteristics for a component within the tariff structure. For example, the energy charge component may vary with the time of day in which electricity is consumed.
CPI	Consumer Price Index.
DBT / Declining block tariff	A tariff whereby the network charge becomes progressively cheaper as customer consumption increases.
Direct control services	Services regulated by the AER under the National Electricity Rules. Direct control services comprise Standard Control Services and Alternative Control Services.
DNSP	Distribution Network Service Provider.
Financial year	The year running from 1 July in any year to 30 June the following year.
Food & Fibre	NSW irrigators and growers. A proposed tariff class and customer type.
HV	High voltage.
IDT	Inter distributor transfer – a type of customer.
kVA	Kilovolt ampere.
kW	Kilowatt.
kWh	Kilowatt hour.
LRMC	Long run marginal cost – economic term for the cost of adding one more unit of demand to the network.
LV	Low voltage.
NEL	National Electricity Law.
NEO	National Electricity Objective.
NMI	National Meter Identifier – each meter installation has a unique NMI.
NUOS	Network Use of System – this is the charge for using Essential Energy's distribution network, as well as the pass through of transmission type costs and jurisdictional scheme amounts such as the climate Change Fund.
Peak demand / peak load	The maximum electricity demand customers place on the electricity network.
Solar PV	Solar Photovoltaic system.
Standard Control Services	Comprise Essential Energy's core activities from access to, and supply of, electricity to customers.
Tariff	A cost charged to network customers to recovers the efficient costs of providing network services.
Tariff class	A group of customers that share a common set of characteristics that allows them to be grouped together to ensure that similar customers pay similar prices.
Tariff component	Tariffs comprise one to three tariff components that work together to reflect the efficient costs of providing network services to customers. The three components are: Fixed charge, Energy charge and Demand charge.
Tariff schedule	The list of prices and tariff structures for each of our tariffs, published annually. Also referred to as Network Price List and Explanatory Notes.
Tariff structure	How tariff components are combined to give the tariff structure.
The Rules	The National Electricity Rules.
TOU	Time of Use – a meter or tariff that varies with when electricity is consumed in either a: peak; shoulder; or off-peak period.
TSS	Tariff Structure Statement.
TUOS	Transmission Use of System – this is the cost Essential Energy pays for the use of transmission networks.
VNM	Virtual Net Metering

ABOUT THIS TARIFF STRUCTURE STATEMENT

Requirements of a Tariff Structure Statement

This document is Essential Energy's proposed Tariff Structure Statement (TSS) for the period 1 July 2017 to 30 June 2019. The purpose of this TSS is to demonstrate how Essential Energy has adopted the new network pricing objective as set out in Section 6 of the National Electricity Rules (the Rules) and complied with the associated pricing principles. This TSS applies to direct control services.

The objective set out in the final Rule is that the network prices that a distribution network service provider (DNSP) charges each customer should reflect the business' efficient costs of providing network services to that customer.

The pricing principles with which Essential Energy must demonstrate compliance are:

- Each network tariff must be based on the long run marginal cost (LRMC) of providing the service. LRMC is a measure of the future network costs that are incurred by using one more unit of energy, adding one more customer to the network, or the costs that could be saved by using less energy
- The revenue to be recovered from each network tariff must reflect the DNSP's total efficient costs of providing services to the customers assigned to that tariff
- DNSPs must consider the impact on consumers of changes in network tariffs and must develop tariffs which are reasonably capable of being understood by customers
- Network tariffs must also comply with any jurisdictional pricing obligations imposed by state or territory governments
- The revenue expected to be recovered from a tariff class must lie between the stand alone cost of providing the service to the relevant customers and the avoidable cost of not providing the services
- Side constraints which limit annual price movements within a tariff class are to be adhered to.

This proposed TSS seeks to provide a clear explanation of our network tariffs so as to facilitate a greater level of understanding by customers and enable them to make more informed choices about how they use their electricity service.

TSS layout

Essential Energy's proposed TSS contains the following sections:

- Section 1 – Executive Summary
- Section 2 – About Us
- Section 3 – Understanding Our Network Costs and Tariffs
- Section 4 – The Need for Tariff Reform
- Section 5 – Engaging Our Customers and Stakeholders
- Section 6 – Our Proposed Network Tariff Structures
- Section 7 – Our Tariff Setting Methodology.

How we address the TSS Rule requirements

Table A-1-1 on the following page will help customers navigate to where Essential Energy has addressed each of the TSS Rule requirements within this TSS.

Supporting documentation

A list of the ten Attachments to this TSS are summarised at the bottom of the Table of Contents.

Feedback on this TSS

A key objective of this TSS is to reflect on the views of our customers and stakeholders when preparing our proposal. Essential Energy's customers and stakeholders can provide feedback on this proposed TSS and supporting documents through the following channels:

Channel	Details
Email	ourplans@essentialenergy.com.au
Post	Manager Network Regulation Essential Energy PO Box 5730 Port Macquarie NSW 2444
Phone	13 23 91
Twitter	twitter.com/essentialenergy

Customers can also provide feedback and comments on Essential Energy's Tariff Structure Statement to the AER at www.aer.gov.au.

Table A-1-1: How to find where Essential Energy has addressed the TSS Rule requirements

Requirement	Rule reference	Location within the TSS
Describe how the proposed TSS complies with the pricing principles and outline any departures from the pricing principles.	6.8.2(c)(7) Note that transitional rules mean this requirement is to be met by 27 November 2015	Section 7.6 - Summary of compliance with the distribution pricing objective and principles and Attachment 4 - *Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles from Houston-Kemp*
The TSS must be accompanied by an indicative pricing schedule.	6.8.2(d1) & 6.18.1A(e)	Attachment 2 - *Indicative NUOS Pricing Schedule* (for Standard Control Services); and Attachment 7 - *Alternative Control Pricing Schedule*
The TSS must include tariff classes.	6.18.1A(a)(1)	Section 6.2 - Our proposed tariff classes
The TSS must include the policies and procedures for assigning customers to tariffs and reassigning from one tariff to another.	6.18.1A(a)(2)	Section 3.5.6 - Allocating customers to tariffs and Attachment 6 - *Policies and procedures for assignment and reassignment of tariffs*
The TSS must include the structures for each tariff.	6.18.1A(a)(3)	Section 6.3 - Our proposed tariff structures
The TSS must include the charging parameters for each tariff.	6.18.1A(a)(4)	Section 6.3 - Our proposed tariff structures
The TSS must include a description of the approach we will take in setting each tariff in each pricing proposal during the regulatory period.	6.18.1A(a)(5)	Attachment 4 - *Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles from Houston-Kemp* Section 6.5 - Strategy for transitioning customers from non-cost reflective network tariffs to cost reflective tariffs Section 6.6 - Future tariff structures and pricing directions
We must provide an overview paper with the TSS that includes a description of how we have engaged with our customers, retailers and stakeholders in developing the TSS.	6.8.2(c1a)	Attachment 1 - *Overview of this TSS*

1. EXECUTIVE SUMMARY

On 27 November 2014, the Australian Energy Market Commission (AEMC) made a new Rule that requires distribution network service providers (DNSPs) to develop prices that better reflect the costs of providing network services to customers. This document is our first Tariff Structure Statement (TSS), a requirement of the new Rule, and covers the two year period commencing 1 July 2017.

We have developed this TSS in conjunction with our stakeholders. Our customer engagement included one on one conversations with customers and several roundtables with specific stakeholder groups from across our electricity distribution area. In conjunction with Networks NSW, we undertook an extensive media campaign asking our customers to have their say on the proposed tariff reforms via the NSW government 'haveyoursay' website, through our own website, and through traditional means such as mail outs to councils and accredited service providers.

The key objective of this document is to ensure our customers have a clear understanding of:

- Why we are proposing changes to our tariffs
- Our proposed network tariff structures
- How our tariffs promote efficient network investment and utilisation
- The impact on customers of our proposed changes
- How we plan to transition customers to these new network tariffs.

The electricity landscape is changing

In the past, the electricity network was simple, with energy flowing in one direction through a centrally planned system – large scale generators produced energy that was transported through the transmission network, then through the distribution network and on to the customer. Today, the electricity network is far more complex. Solar PV generation has allowed consumers to become electricity generators. The current network system has become more dynamic and integrated, with energy now flowing in opposite directions at different times of the day.

The future network will become even more dynamic as emerging technologies are refined and introduced to the mass market. Consumers will be able to store their own generated energy with battery storage and better manage their electricity consumption through the use of Smart Meters and energy management systems. The increased uptake of electric vehicles could also create pockets of high growth demand on our network.

These changes will have big impacts on our electricity distribution system, so we are starting to act now to better communicate to customers the true cost of their network usage. By providing efficient price signals to customers through our tariffs, we hope to encourage a more even load on our network. This will allow us to defer augmentation (growth) expenditure and, in turn, eliminate unnecessary increases in customer prices. However, if customers are willing to pay more and our tariffs signal this, then that is also an acceptable outcome, even if it leads to subsequent network augmentation.

Our proposed tariff changes

The new Rule requires our electricity network prices to be cost reflective – that is, they should reflect the efficient costs of providing network services to our customers.

Network tariffs form a key component of our overall demand management strategy. In developing our tariffs, we aim to reduce long-term average prices by promoting efficient network investment and utilisation. This TSS sets out how we will achieve this for the period 2017–19.

Our proposed tariff structures are identical to our existing tariff structures and will, therefore, have minimal impact on the majority of our customers. The bulk of our customers have only basic accumulation meters, which has limited the tariff structures we can realistically implement. We are also keen to monitor the success of demand tariff implementation for residential and small business customers in Victoria and other states, due to begin in 2017, to see if they do lead to changes in consumer behaviour. For the period of this TSS we see our declining block tariff as a logical transition towards efficient prices.

We have listened to the feedback from our customers and stakeholders and developed our tariff structures accordingly. Some of the specific features we have taken on board are:

- Key elements of our proposed residential and small business tariff structure are aligned with other NSW distributors to provide consistency for retailers and stakeholders;
- Our tariff structures are simple and easy to understand;
- We will progressively transition customers to our proposed efficient price structures;
- We are introducing separate rates for our peak and shoulder periods;
- We are not proposing location based tariffs, Food & Fibre tariffs, social tariffs or tariffs for customers who export electricity to the network. However these are areas that we will continue to monitor and may introduce in the future.

Under the Rules our tariffs must be based on the long run marginal cost (LRMC) – that is, the future cost of adding one more unit of demand or one more connection – this is considered to be the variable component of a tariff. LRMC is calculated at a voltage level, therefore we have a LRMC for each of low voltage, high voltage and subtransmission. The LRMC is not specific to location or feeder, but an average for all customers connected at the same voltage level. We have identified that some of our existing tariff components are under the LRMC. As such, we will transition towards LRMC tariffs over time while taking into account the impact on customers, as also required under the Rules.

Our actual network tariffs will be determined each year through the Australian Energy Regulator's (AER) annual pricing proposal process, but must comply with the structures set out in our TSS. A summary of our proposed network tariff structures for the 2017–19 period are set out in the following tables.

Table 1-1: Residential customers proposed network tariff structures

Tariff	Tariff structure	Charging parameter
Residential declining block (default tariff)	Fixed	Network access charge as a fixed amount per day
	Energy	Three tier declining block tariff > Step 1 applies to the first 1,000kWh per 91 days > Step 2 applies to consumption >1,000kWh and ≤1,750kWh per 91 days > Step 3 applies to all consumption >1,750kWh per 91 days
Residential Time of Use (opt in tariff)	Fixed	Network access charge as a fixed amount per day
	Energy	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times

Table 1-2: Small Business customers proposed network tariff structures

Tariff	Tariff structure	Charging parameter
Business declining block (default tariff small business)	Fixed	Network access charge as a fixed amount per day
	Energy	Two tier declining block tariff > Step 1 applies to the first 5,000kWh per 91 days > Step 2 applies to consumption >5,000kWh per 91 days
Business Time of Use (opt in tariff small business)	Fixed	Network access charge as a fixed amount per day
	Energy	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times

Table 1-3: Controlled Load customers proposed network tariff structures

<table>
<tr><th>Tariff</th><th>Tariff structure</th><th>Charging parameter</th></tr>
<tr><td rowspan="2">Controlled load 1</td><td>Fixed</td><td>Network access charge as a fixed amount per day</td></tr>
<tr><td>Energy</td><td>Flat rate based on usage between five to nine hours overnight on weekdays and extra hours on weekends except where the load is controlled by a time clock</td></tr>
<tr><td rowspan="2">Controlled load 2</td><td>Fixed</td><td>Network access charge reflecting a fixed amount per day</td></tr>
<tr><td>Energy</td><td>Flat rate based on usage between 10 to 18 hours per day on weekdays and all hours on weekends except where the load is controlled by a time clock</td></tr>
</table>

Table 1-4: Business customers proposed network tariff structures

<table>
<tr><th>Tariff</th><th>Tariff structure</th><th>Charging parameter</th></tr>
<tr><td rowspan="3">Low voltage – Time of Use average daily demand</td><td>Fixed</td><td>Network access charge as a fixed amount per day</td></tr>
<tr><td>Energy</td><td>Peak, shoulder and off-peak rate based on energy consumed in each period
> Peak period is from 7am to 9am and 5pm to 8pm on weekdays
> Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays
> Off peak period is at all other times</td></tr>
<tr><td>Demand</td><td>Demand charge calculated on the average daily time of use demand for peak, shoulder and off-peak periods for the month.</td></tr>
<tr><td rowspan="3">Low voltage – Time of Use three rate demand</td><td>Fixed</td><td>Network access charge as a fixed amount per day</td></tr>
<tr><td>Energy</td><td>Peak, shoulder and off-peak rate based on energy consumed in each period
> Peak period is from 7am to 9am and 5pm to 8pm on weekdays
> Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays
> Off peak period is at all other times</td></tr>
<tr><td>Demand</td><td>Maximum demand charge based on the highest measured half-hour kVA demand registered in each of the peak, shoulder and off-peak periods during the month.</td></tr>
<tr><td rowspan="3">Low voltage – Time of Use demand alternative</td><td>Fixed</td><td>Network access charge as a fixed amount per day</td></tr>
<tr><td>Energy</td><td>Peak, shoulder and off-peak rate based on energy consumed in each period
> Peak period is from 7am to 9am and 5pm to 8pm on weekdays
> Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays
> Off peak period is at all other times</td></tr>
<tr><td>Demand</td><td>Maximum demand charge based on the highest measured half-hour kVA demand registered in either the peak or shoulder periods during the month.</td></tr>
</table>

Table 1-5: Large Business customers proposed network tariff structures

Tariff	Tariff structure	Charging parameter
High voltage – Time of Use average daily demand	Fixed	Network access charge as a fixed amount per day
	Energy	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times
	Demand	Demand charge calculated on the average daily time of use demand for peak, shoulder and off-peak periods for the month.
High voltage – Time of Use monthly demand	Fixed	Network access charge as a fixed amount per day
	Energy	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times
	Demand	Maximum demand charge based on the highest measured half-hour kVA demand registered in each of the peak, shoulder and off-peak periods during the month.

Table 1-6: Large Business Subtransmission customers proposed network tariff structures

Tariff	Tariff structure	Charging parameter
Subtransmission – three rate demand	Fixed	Network access charge as a fixed amount per day
	Energy	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times
	Demand	Maximum demand charge based on the highest measured half-hour kVA demand registered in each of the peak, shoulder and off-peak periods during the month.
Site specific	Various	Various combinations of fully cost reflective structures

Table 1-7: Unmetered customers proposed network tariff structures

Tariff	Tariff structure	Charging parameter
LV Unmetered NUOS	Fixed	Network access charge reflecting a fixed amount per day
	Energy	Flat rate based on usage
LV Public Street lighting TOU NUOS	Energy	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times

2. ABOUT US

This section of our TSS explains who we are, our responsibilities, values and the challenges we face in operating our network.

2.1 Our business

Essential Energy is a NSW Government-owned corporation with responsibility for building, operating and maintaining Australia's largest electricity network – delivering essential network services to approximately 823,000 rural and regional customers across 95 per cent of NSW and parts of southern Queensland. We operate under a decentralised regional management structure, with three regional management teams responding to local needs and priorities.

Our electricity distribution network is funded through a five-yearly distribution network revenue determination made by the AER in accordance with the National Electricity Law (NEL) and National Electricity Rules (the Rules). The current determination covers the period from 1 July 2014 to 30 June 2019 (2014-19 Determination).

The AER assesses and approves distribution network revenues and expenditure at a level it deems to be efficient and prudent. Prices are then set to allow recovery of these revenues and are approved by the AER on an annual basis to ensure compliance with the revenue determination.

2.2 Our business purpose & values

Essential Energy's core focus is on ensuring safe, affordable and reliable delivery of essential services. We are committed to delivering better value for our customers by reducing our costs without compromising safety or services, and we aim to:

> Be safety focused
> Be customer centred
> Operate a sustainable network
> Ensure that we have capable and committed employees.

Essential Energy requires our employees and contractors to understand and support our corporate values. The following five values and their associated behaviours form the basis of everything we do:

2.3 Our network

Geographically, our electricity distribution network covers 95 per cent of NSW (as shown in Figure 2-1 below), from humid coastal environments in the north coast region, through semi-arid desert in the far west, alpine peaks in the south and a grain belt that crosses central NSW from north to south.

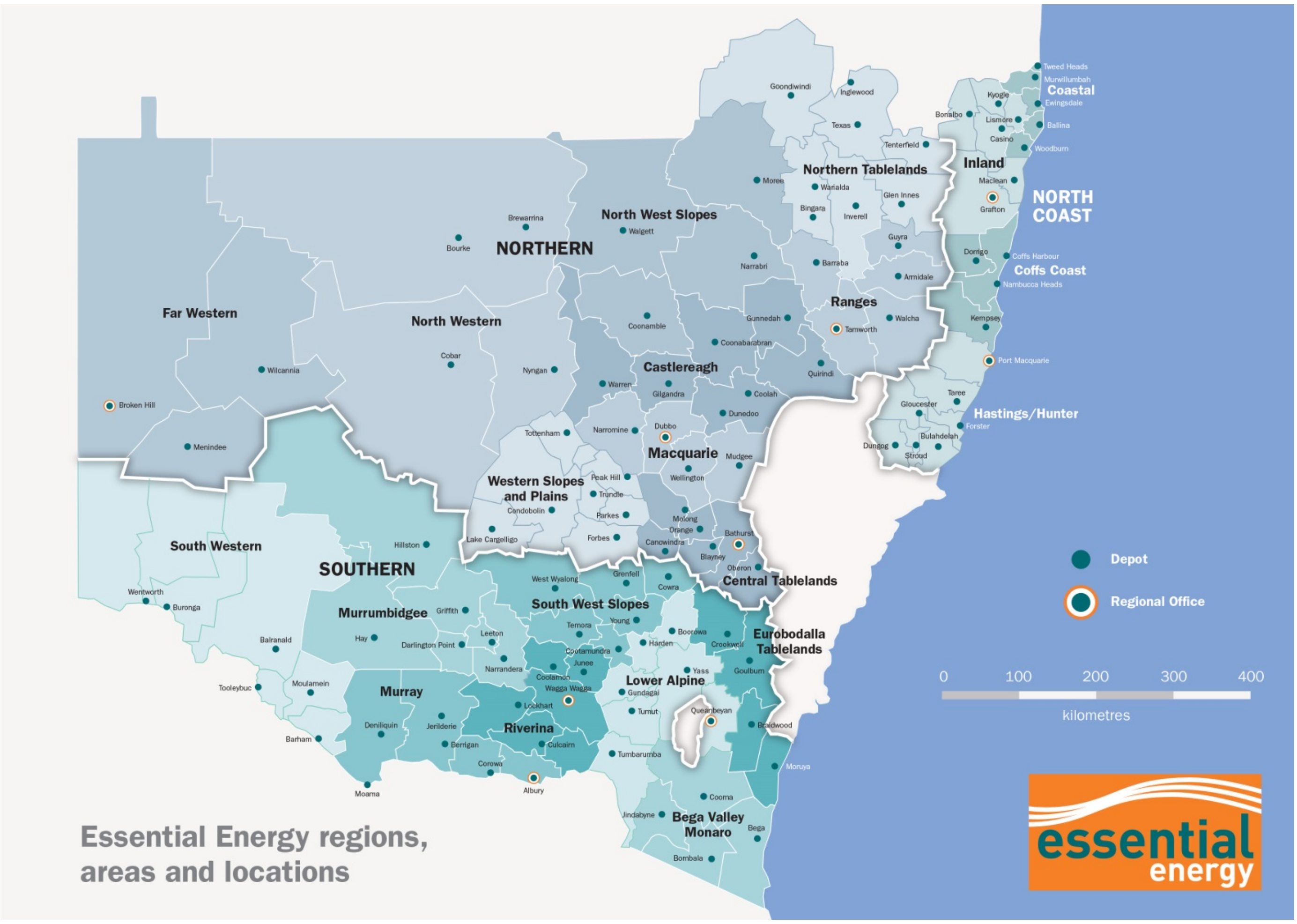
As a network operator, Essential Energy provides a range of services – including ownership, planning, design, construction, operation and maintenance of distribution network infrastructure – to transport and distribute electricity safely and reliably to customers connected within our distribution area. Customers may choose any electricity retailer.

Essential Energy network statistics*

Route line length: (overhead spans)	**181,384 km**
Network area:	**737,000 sq. km**
Customer density: (per km route line length)	**4.78 customers/km**
Zone substations:	**400**
Substations:	**135,000**
Poles:	**1,319,497**
Streetlights:	**154,009**

* As at 30 June 2015

Figure 2-1: Essential Energy's distribution network area



2.4 How our network transports electricity

To enable us to obtain informed feedback on our plans and priorities, it is important that our customers and other stakeholders understand the overall electricity supply chain and Essential Energy's role within this chain as a NSW electricity distributor.

There are five main activities within the electricity supply chain:

> Generation – the process of producing electricity from power stations. There are various power station sources including: coal, oil, gas, solar and wind

> Transmission – the process of carrying electricity at high voltages from power stations, either by overhead or underground cables

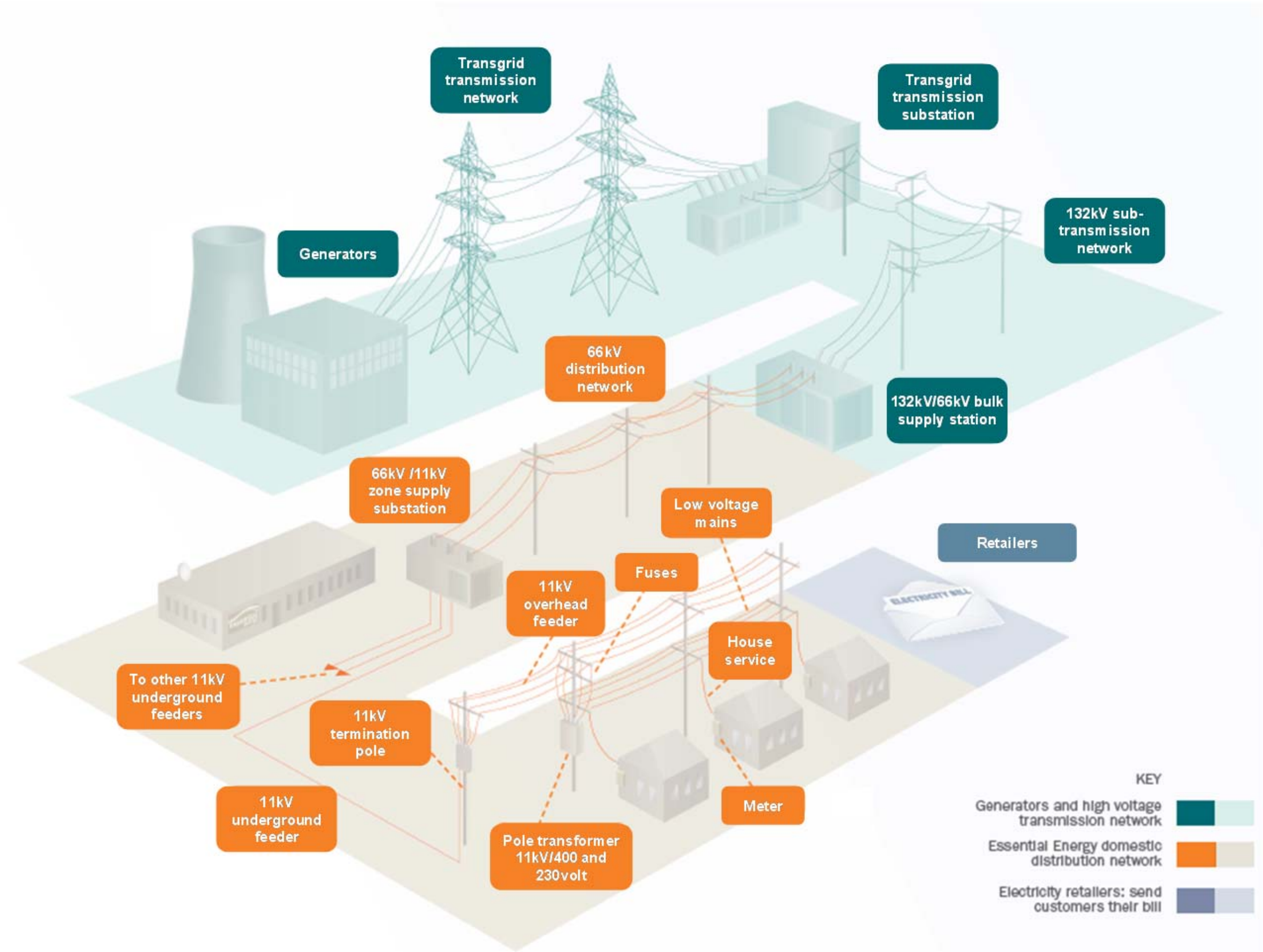
> Distribution – the process of delivering electricity from the high voltage transmission systems to the regional subtransmission system, then through local powerlines, transformers and substations to customers

> Retailers – who process customers' accounts for their electricity usage

> Metering services – electricity meter supply, meter reading and meter maintenance activities.

Figure 2-2 below outlines the electricity supply chain infrastructure and highlights the portion for which we are responsible.

Figure 2-2: Electricity supply chain



2.5 Our network challenges

Our distribution network comprises*:

- 823,436 customers and 1,319,497 poles spread across 737,000km^2
- We have 1.6 power poles for every customer
- **181,384 kilometres of overhead powerlines** – equivalent to driving around Australia 13 times
- For every kilometre of overhead powerline we have just 4.78 customers to pay for it
- **1,447 feeders with the longest circuit being 1,900km long** – the same distance as driving from Sydney to Melbourne and back again
- Every field employee is effectively responsible for 79 kilometres of powerlines
- Our network assets have an average age of almost 35 years

* As at 30 June 2015

2.5.1 A radial network

Essential Energy's network is largely radial. This means many of our customers are supplied through just one powerline and power can't be re-routed or switched to restore power during supply interruptions.

It is often difficult to locate and repair radial line faults due to the distance needed to travel to find the fault.

2.5.2 A largely rural network

Around 80 per cent of our network is rural. These lines supply sparsely populated areas and carry lower loads along very long distances, facing greater exposure to environmental factors.

We often have to install asset components with a greater capacity (and greater cost) than our required demand to account for the drop in voltage that occurs as electricity travels along our vast network lengths.

2.5.3 Environmental and weather conditions

Weather is a common cause of unplanned supply interruptions. Windy conditions along the coast contribute to salt build up on insulators and equipment, resulting in failures. Timber power poles in the North Coast region are prone to increased fungal decay as a result of high humidity.

West of the Dividing Ranges, the rural lines traverse open rolling terrain with scattered vegetation. This exposes our network to storms and associated lightning strikes, which often cause damage to our assets.

With vegetation, dry land and lightning, comes bushfires. Bushfire prone areas make up a large portion of our network.

15,409 lightning strikes per year on the network.

2.5.4 Network access

Our regional and rural distribution area means our crews travel long distances, often across difficult terrain. This imposes additional challenges and adds time to restoring power and maintaining our assets.

Crews often utilise access roads that have not been driven on for years – fallen trees and overgrown vegetation need to be cleared. Many gravel or dirt trails can remain impassable for weeks following heavy rain.

Our crews also need to be mindful of wildlife when driving at dawn, dusk and during the night to reduce the chance of an accident.

The local knowledge of our employees is integral to identifying fault locations and readily accessing our network to restore power.

During 2013-14, our fleet travelled 61 million kms - equivalent to driving around Australia 4,200 times.

2.5.5 Managing vegetation

Vegetation management is Essential Energy's largest single operating expense, after labour. The costs of managing vegetation around the network are driven by the size of our geographic area, the volume of trees that require trimming and the extent to which trees need to be trimmed.

Essential Energy has, on average, more trees to maintain per span due to a longer average span length than most distributors. The longer a span, the greater the clearance zone required to account for the potential blow out of conductors in high wind conditions.

Proactively managing vegetation around the network:

> Reduces the risk of bushfires igniting from contact between vegetation and network assets;

> Reduces the number of reliability performance issues that arise from vegetation contact on the network; and

> Reduces the number of outages from trees and branches falling onto powerlines during storms.

1,039,217 spans on Essential Energy's network are in designated high bushfire zones. The typical clearance zone is 4 metres.

2.5.6 Inherited network characteristics

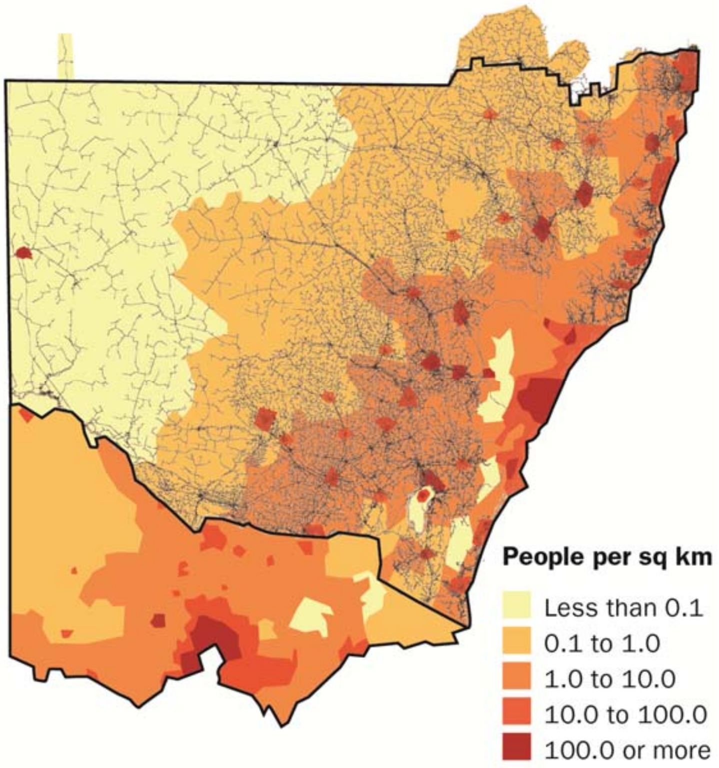
The bulk of our network was built at 11,000 volts, whereas modern rural networks are now built at 22,000 volts. The dominance of an 11,000 volt system is not ideal as it is more expensive to reticulate (requiring more and larger assets).

However, it is not feasible and would be cost prohibitive to reconstruct the network to the design we would choose to build today.

2.5.7 Low customer density

In contrast to other DNSPs, we have one of Australia's lowest average customer densities – less than five customers per kilometre of power line. As a result, our average distribution charge is higher than other network areas across Australia because, relative to the territory our network covers, we have far fewer customers to pay for it – see Figure 2-3.

Figure 2-3: We have very low customer density per kilometre of powerline



Stylised population density from, Australian Bureau of Statistics, SA2 June 2014

2.5.8 Demand growth

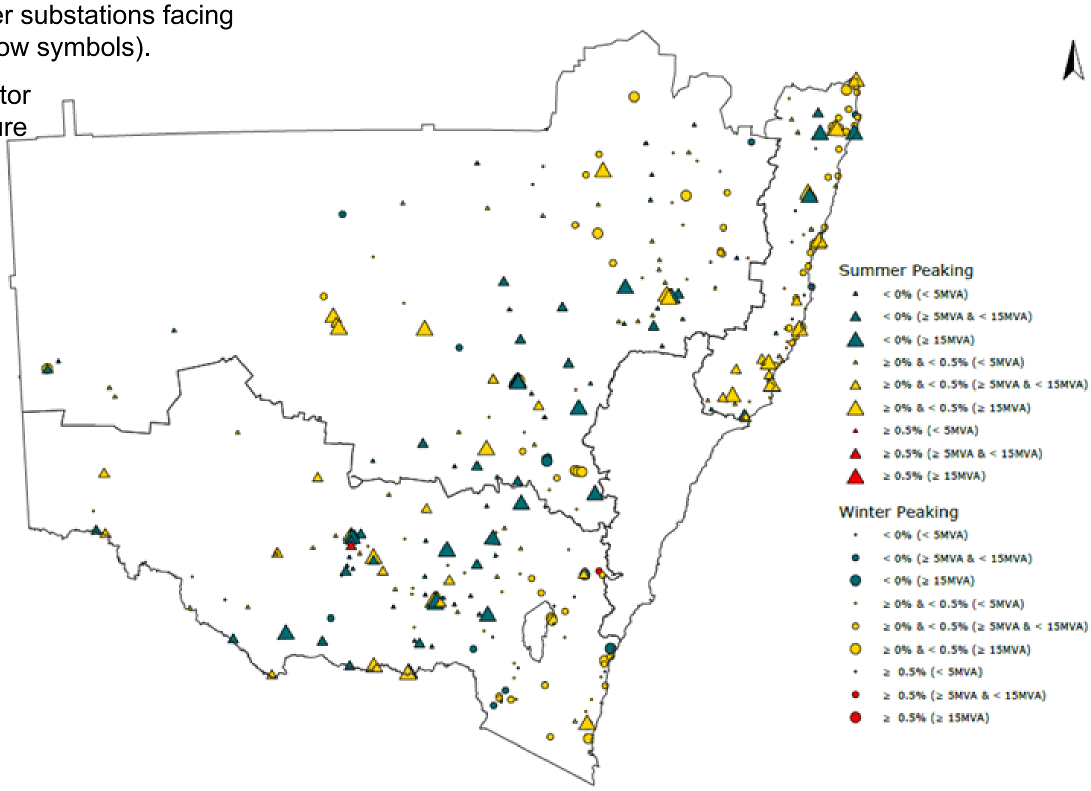
In recent years our small customer consumption has generally decreased across most of the network, with pockets of growth mostly on the north coast and in regional centres. The steady uptake of solar PV technology has, no doubt, played a part (see section 4.3.1). However, the number of large mines operating across our network has negated these reductions, and overall demand on our network has been fairly flat.

Our expected growth areas, based on zone substation demand, are shown in Figure 2–4. The red symbols indicate the zone substations experiencing the greatest demand pressure, through to the green symbols experiencing the least pressure. Triangles represent summer demand peaks and circles winter demand peaks. The larger the symbol, the greater the demand pressure.

While there are only two zone substations experiencing high demand pressure (red symbols), there are numerous other substations facing increased pressure (yellow symbols).

We will continue to monitor network demand to ensure necessary, efficient investment continues to takes place.

Figure 2-4*: *Our areas of expected network growth



3. UNDERSTANDING OUR NETWORK COSTS AND TARIFFS

This section outlines the expenditure we incur in managing our distribution network; the causes (drivers) of our network costs; the services covered by this TSS; and an explanation of tariff related terminology.

3.1 Our network expenditure

Our network expenditure is largely fixed as our cost drivers do not significantly vary in the short to medium term. In managing our electricity distribution network, Essential Energy incurs two types of expenditure that are ultimately paid for by customers:

> Capital expenditure - for installation of new assets or the replacement of old ones, or to meet reliability or quality standards, or environmental, safety or statutory obligations. Network assets are generally expensive, but last for relatively long periods of time – that is, they have long asset lives. Rather than have customers pay for these capital costs in one lump sum as they are incurred, they are paid for gradually, over the life of the asset, by the customers they serve.

> Operating expenditure - for the day to day costs of asset inspection, repairs and maintenance, vegetation management and other associated network costs. Operating expenditure is recovered from customers over the regulatory period in which it is incurred.

3.2 Network cost drivers

There are three drivers of costs involved in owning and operating an electricity distribution network. These are:

> The number and condition of assets

> Network demand

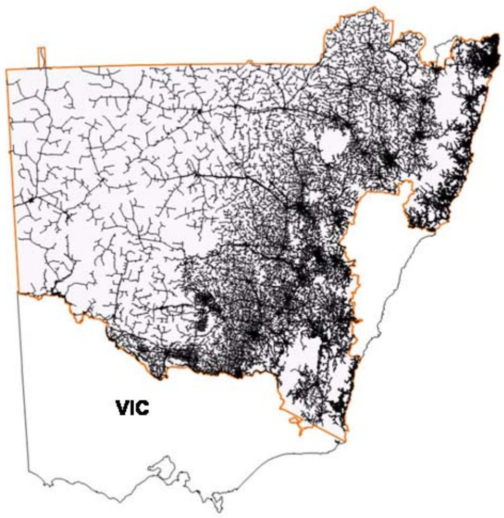
> Customers (and density).

As a rural network operator, about 70 per cent of our costs are driven by the number of our assets and their spread across our large network area. It is well-recognised that, as distribution networks becomes less dense (with less customers per kilometre), the number of assets becomes the more dominant cost driver, forming 60 to 70 per cent of a rural operator's operating costs[1]. We need to inspect, maintain, and replace these assets to ensure they are safe and do not cause death or injury, do not cause bushfires, are reliable and deliver all the service outcomes required by customers.

Network demand is our second most important cost driver, while customer numbers have only a small impact on our overall costs. Each of these drivers is discussed in more detail below.

3.2.1 Assets and network area

Essential Energy's network is unique in terms of the geographic area it covers, the terrain it traverses, the vegetation that grows within it and the diversity of weather that passes over it. While the majority of our customers are located on the east coast and in major inland towns and cities, we must provide network connection services to all customers within our footprint.



The scale of assets required to ensure the network physically extends to connect customers in the farthest parts of regional, rural and remote NSW is like no other network in Australia. Such a vast network spread across a range of environments presents unique and ongoing challenges as described in section 2.5. The sheer size of our network and the associated number and condition of assets is the major driver of our service delivery costs.

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[1] EMCa, *Relationship Between Opex and Customer Density for Sparse Rural Networks*, April 2015, p.1

3.2.2 Network demand

Essential Energy's network has been developed to serve the demand for electricity that customers impose on it. Higher demand requires more assets to be constructed and financed. Additional plant and equipment may also be required to maintain a reliable and safe power supply.

Once customer demand for electricity exceeds the capacity of that part of the network, the system is upgraded or augmented to provide increased capacity. This takes place at different levels throughout the network, including high voltage, subtransmission, low voltage mains and substations. While increased capacity to meet higher demand is generally achieved in incremental steps and extensions over time, it is expensive.

As a vast rural distributor, with very low customer density, Essential Energy has challenges that make our asset utilisation on a demand basis look lower than that of a city, urban or less dense rural network distributor. These include:

- The minimum size of assets available to service customers often exceeds the actual level required. This lowers the appearance of our network utilisation and adds to our costs.
- We often have to install asset components with a greater capacity (and greater cost) than our required demand to account for the drop in voltage that occurs as electricity travels along our vast network lengths. Again this makes our asset utilisation look low. This is further exacerbated by the fact that, historically, the bulk of our network was built at 11,000 volts, whereas modern rural networks are now built at 22,000 volts. This means our current network is dominated by an 11,000 volt system which is more expensive to reticulate, as it requires more and larger assets.

Essential Energy is forecasting a small decrease in demand over the coming years.

3.2.3 Customers

Customer related costs cover the maintenance of service connection equipment, such as metering, load control receivers and service lines, and administration costs associated with connecting a customer to the network.

Generally, these costs increase as the number of customers increases. The costs may vary with the size of the customer, but not necessarily in proportion to their energy or demand requirements.

For example, if a new customer joins the network, they will require at least one electricity meter. This meter will require connection, maintenance and reading. The customer may also require additional load control devices to be installed. The additional customer connection will also give rise to administrative costs such as network-related customer account maintenance, billing and collections and price setting calculations.

Essential Energy experiences approximately 7,000 to 10,000 new customer connections each year.

3.3 How our network costs are recovered from customers

Essential Energy applies a network tariff charge – known as the Distribution Use Of System (DUOS) charge – to electricity bills to recover the costs of delivering electricity to our customers. This is the major part of the total network charge, which also includes transmission use of system charges and pass through costs such as the NSW Climate Change Levy.

3.3.1 Tariff regulation and control

Once every five years, the AER assesses Essential Energy's forecast expenditure for building and maintaining our network for the next five years and approves allowances for both capital and operating expenditure, as well as a revenue allowance, at a level it determines to be efficient and prudent.

Our current five-year regulatory period runs from 1 July 2014 through to 30 June 2019. In issuing Essential Energy's funding determination for this period, the AER has:

- Set a revenue allowance for distribution network services for each financial year within this period
- Set prices for metering, public lighting and ancillary network services (Attachment 7 - *Alternative Control Pricing Schedule*).

The prices set to allow recovery of the costs Essential Energy incurs are approved by the AER on an annual basis to ensure compliance with the revenue determination. The network tariffs contained in the annual pricing proposal process must comply with the structures set out in our TSS, and the prices we charge customers for using our network must deliver our revenue allowance.

Essential Energy publishes network tariffs annually in our tariff schedule – our price list – for each financial year 1 July to 30 June.

3.3.2 How customers are charged

Our network charges (and metering service charges for most of our small customers) are passed on to electricity retailers, who in turn charge customers through their electricity bills. The electricity bills most small customers receive from their Retailers do not generally specify our network (and metering) charges, so customers are unlikely to see our prices on their electricity bills. Retailers do not have to charge customers in the same tariff form we use to pass on our charges - for example, our residential declining block tariff may be absorbed into a flat tariff charged to the customer by the Retailer.

The AER determination process ensures Essential Energy is not able to recover unnecessary or inefficient costs. Recovery of our efficient costs of operation will ensure we remain a sustainable business and continue to operate a safe, reliable and value for money electricity network that serves the long-term interests of our customers.

The revenue we can recover from our customers is capped by the AER. This means if we collect more revenue in a financial year – for example, if customers use more energy than we expected, then we must repay the over-recovery to customers. This over-recovery would be included in calculating the tariffs for subsequent years. The reverse also applies – if customers use less energy than forecast and Essential Energy under-recovers its approved revenue allowance in a financial year, this shortfall would be included in calculating subsequent year tariffs.

The range of network costs and their contribution to a typical residential bill are shown in Figure 3-1 below. The orange components are added together in a customer's bill to give the total network charge. The green components are added to a customer's bill by the Retailer.

Figure 3-1: Components of an average 2013-14 customer electricity bill

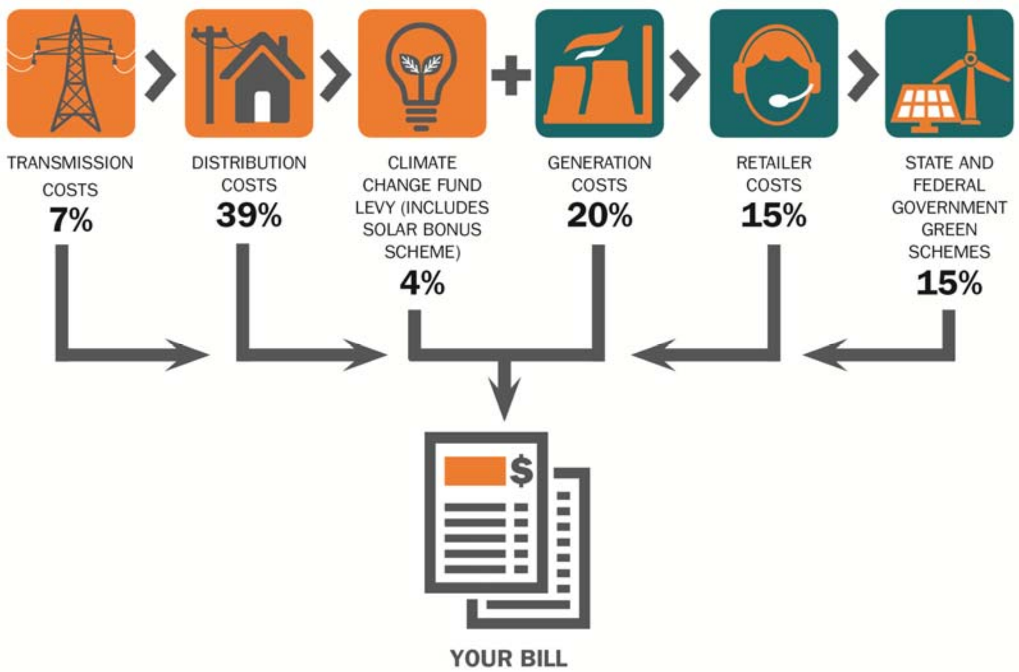


Figure 3-1 shows that in 2013-14, total network charges represented about 50 per cent of an average customer's electricity bill, with the portion retained by us, as the network business, forming 39 per cent.

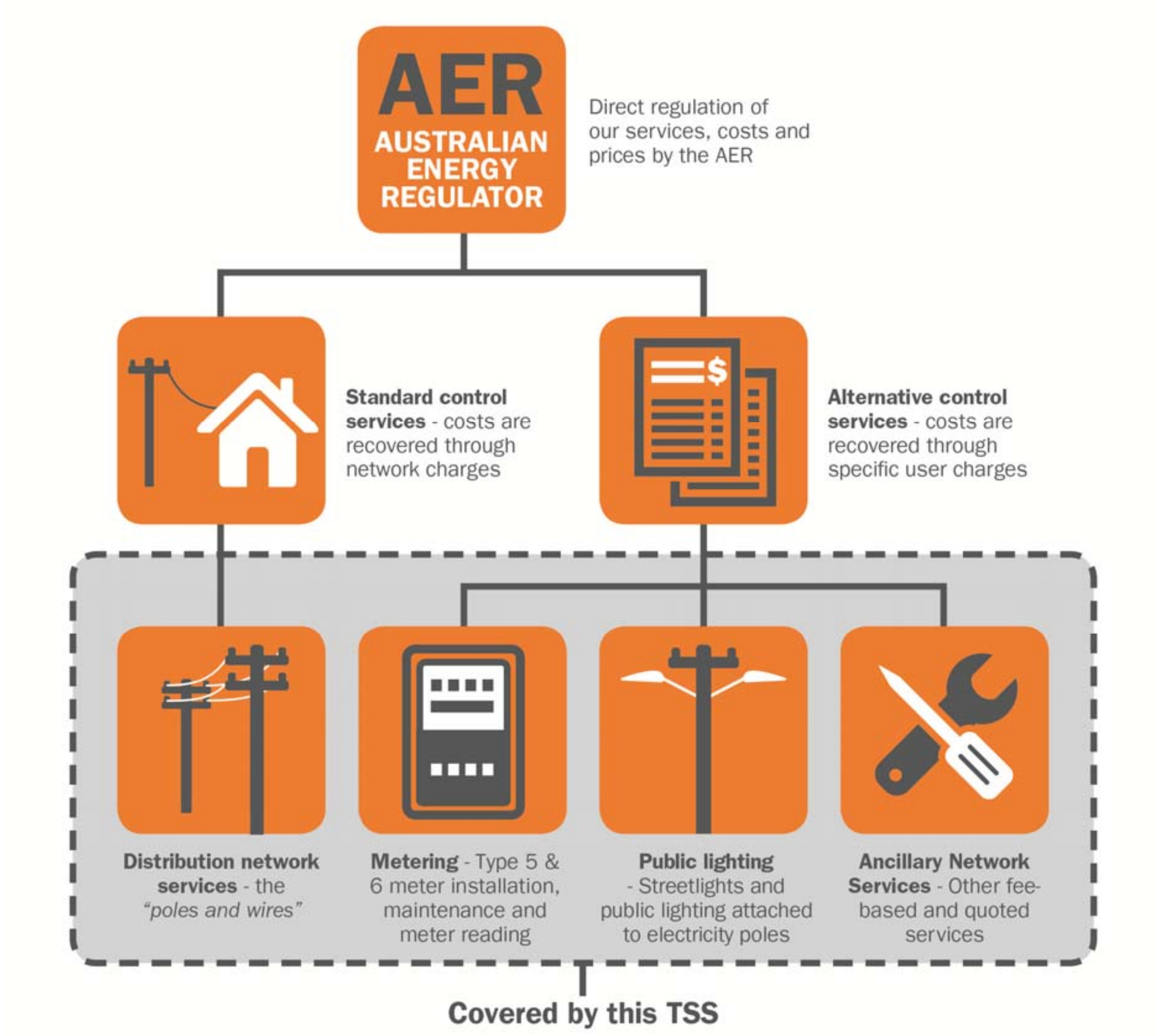
It is important to note, that metering services (meter supply, maintenance and meter reading) do form a component of customer bills. For most residential and small business customers (with Type 5 and 6 meters), the metering charges form part of our distribution costs. For other customers, these services are provided by a separate meter supplier who bills the Retailer (who in turn charges the customer) – these customers would have the metering charge separately identified on their retail bill. More explanation on meter types can be found in section 3.5.5.

3.4 The services covered by this TSS

This TSS describes the network tariffs that are classified as direct control services under the National Electricity Rules. Direct control services comprise *Standard Control Services* and *Alternative Control Services*.

- Standard Control Services - This category relates to the distribution network – the “poles and wires”. Costs are recovered through *general* network charges.
- Alternative Control Services - The main items categorised as Alternative Control Services are Type 5 and 6 metering, public lighting and ancillary network services. These services are recovered through *specific* user charges.

Figure 3-2: The services covered by this TSS



These categories are described in more detail in Table 3-1 below, including the details of how the relevant costs are recovered from customers.

Table 3-1: Essential Energy's services covered by this TSS

1. Distribution network services		
	*Comprise:* > Essential Energy's core activities from access to end supply of electricity to customers. > These services also encompass network maintenance, emergency response and replacement services to ensure continued network reliability and the safety of customers and employees.	*Cost recovery through:* > Our distribution network tariffs which are charged to electricity Retailers. > Electricity Retailers include this cost in the retail prices they charge customers.
2. Metering services		
	*Comprise:* > The installation, maintenance and reading of Type 5 and 6 electricity meters. These are basic accumulation meters and Time of Use accumulation meters. More information on metering types can be found in section 3.5.5. Note: For customers with meter types other than 5 and 6 and for customers who purchase their meter after 1 July 2015, these services are not provided by us – they are provided by an external supplier in a contestable market.	*Cost recovery through:* > An annual fixed charge added to our network charges. As such, these customers will likely not see a separate metering services charge on their retail bill. Note: For customers with meter types other than 5 and 6, the external supplier bills the electricity Retailer who then on-charges the customer. These customers would generally see metering services as a separate item on their retail bill.
3. Public lighting		
	*Comprise:* > The installation and maintenance of public streetlights.	*Cost recovery through:* > AER approved prices charged to local councils.
***4.* Ancillary network services**		
	*Comprise:* Services that are specifically requested by individual customers. There are two broad categories of ancillary network services: > Fee-based services – these are services with largely fixed costs, regardless of the type of customer or their location. Examples include electricity connections or design and inspection services. > Quoted services – these are services for which costs vary depending on the particulars of the job, such as the site conditions or location of the work. As such each job is quoted individually based on approved labour rates.	*Cost recovery through:* > These services are generally charged directly by the network business to the customer or their Accredited Service Provider. > Some services, such as disconnection, will be charged to the customer's Retailer and they will pass these charges on to the customer

3.5 Understanding our network tariffs and charges

3.5.1 Tariff classes

In general terms, Essential Energy's tariffs vary in accordance with the voltage level at which electricity is taken from the network and a customers' level of consumption. Rather than setting specific prices for every customer on our network, we group customers with similar characteristics together into a *tariff class*. This allows us to break our approximately 823,000 customers down into broad classes, which ensures that customers with similar consumption profiles, demands and costs pay similar prices.

Within each tariff class, there may be more than one tariff that a customer may choose from, and each tariff is made up of a number of components that are described in section 3.5.2 below.

3.5.2 Tariff structures, tariff components & charging parameters

Each tariff has its own structure, comprising between one and three *tariff components*. When added together, the components represent how Essential Energy has decided to charge customers to ensure the price they pay reflects the efficient costs of the network services we provide.

Each Essential Energy network tariff is made up of one or more of the following components:

> *A fixed charge* component – an annual supply charge that applies to each connected premise to which electricity is delivered. The amount does not vary with the amount of energy a customer uses. This component is charged as a fixed amount per day.

> *An energy charge* component - a charge that is applied to each unit of electricity consumed in cents per kilowatt hour (kWh). Depending on the particular tariff, the consumption charge may also vary with the time of day or the amount of energy consumed in a period.

> *A demand charge* component - a charge that is applied to either a customer's maximum demand level in dollars per kilovolt-ampere (kVA) or per kilowatt (kW) or their electricity capacity requirement in dollars per kVA - depending on the tariff.

An annual *metering charge* is also applied to each customer premise for which we provide Type 5 and 6 metering services (which is most residential and small business customers). This is charged as a fixed amount per day.

A tariff may include specific charge characteristics for a component within the tariff structure. For example, the energy charge component may vary with usage, the time of day at which electricity is consumed, or a demand charge component may specify a minimum charge level. Each different component of a tariff is known as *charging parameters*.

Most of our residential and small business customers are currently on tariffs that comprise a fixed charge (which includes a metering charge) and an energy charge (consumption) component. Most of our other business customers are on tariffs that comprise all three charge components (as well as an additional metering charge from their metering services provider).

3.5.3 Price levels

Once we have a tariff structure, we set the level of each tariff component. These are known as price levels and outline the amount we charge per annum for fixed and metering services, the rate per kilowatt for the consumption charge and the rate per kilowatt hour or per kilovolt-ampere for the demand charge.

3.5.4 Example tariff structure

Table 3-2 below shows an example of a tariff structure for the 'Low Voltage Energy' tariff class. The tariff has two *charging parameters* - a *fixed charge* and an *energy charge*.

Table 3-2: Example tariff structure

Tariff Class	Tariff Name	Tariff Structure			
		Fixed charge	**Energy charge**		
		Network Access $/Day	**Energy Block 1 c/kWh**	**Energy Block 2 c/kWh**	**Energy Block 3 c/kWh**
Low Voltage Energy	Residential declining block	0.7705	9.4654	9.1474	8.8295

More detailed information on our tariff structures is set out in section 6 and our indicative network tariff prices are outlined in Attachment 2 - *Indicative NUOS Pricing Schedule*.

3.5.5 Types of meters

The type of meter a customer has is important in determining the tariff(s) to which they can be allocated. There are many different types of electricity meters, however, they can be broadly classed into the following four groups:

1. Basic accumulation meters (also known as Type 6 meters) – These meters measure only the total amount of electricity consumed over a period and are manually read by a meter reader. There are two types of meters within this category: those that record total usage within set periods (these can be aligned to a Time of Use tariff); and those that record only total usage. Most residential and small business meters within Essential Energy's network area are this type of meter – a total of 1,452,496 meters as at 30 June 2015.
2. Type 5 meters – These meters record electricity consumption in 30 minute intervals and are manually read by a meter reader. As at 30 June 2015, we have a total of just 551 Type 5 meters in our network area.
3. Interval meters – These meters record how much electricity is used in every 30 minute interval and the associated demand. This allows customers to select a tariff that has different rates for usage at different times of the day. These meters have communications attached so are remotely read and are known as Type 1 to 4 meters.
4. Smart Meters – These meters record customer usage and demand in real time and are remotely read in 30 minute intervals. Smart Meters can be linked to in-home devices to allow customers to make informed decisions about their electricity consumption.

A tariff is assigned to each meter, so where a customer has more than one meter – for example, a continuous supply meter and an off-peak (Controlled Load) meter – they will have a second tariff applied.

3.5.6 Allocating customers to tariffs

Customers are assigned to tariffs based on their technical properties, such as their load (demand and/or usage), the voltage level at which they are connected to the network and their metering characteristics (meter type).

Essential Energy uses the following system of assessment to assign or reassign customers to an appropriate tariff:

1. Assign the customer to the appropriate tariff class based on the tariff class criteria.
2. Assign the customer to the appropriate tariff within the tariff class. This is based on the customer's connection, load and metering characteristics, as well as the customer type, for example, residential or business.

Tariff assignment occurs when a customer commences consumption of electricity from a new connection point. Essential Energy uses the estimated information collected from the Retailer's service order in conjunction with the system of assessment outlined above to assign the new customer to the appropriate tariff. For a change of occupancy, Essential Energy will normally assign the customer to the tariff that previously existed at the premises.

When a new customer is assigned to a tariff, that tariff will continue to apply until such time as

> Essential Energy receives a request from the customer's *Retailer* to review the *tariff* to which the existing *customer* is assigned as a result of a change in the *customer's load, connection* and/or *metering characteristics* (i.e. *Retailer* applies for a *tariff* reassignment on behalf of the *customer*); or

> Essential Energy, through its own review process, believes that an existing *customer's load, connection* and/or *metering characteristics* have changed such that it is no longer appropriate for that

customer to be assigned to the *tariff* to which the *customer* is currently assigned. Essential Energy initiates the *tariff* reassignment by providing a notice to the customer's *Retailer* prior to the actual *tariff* reassignment.

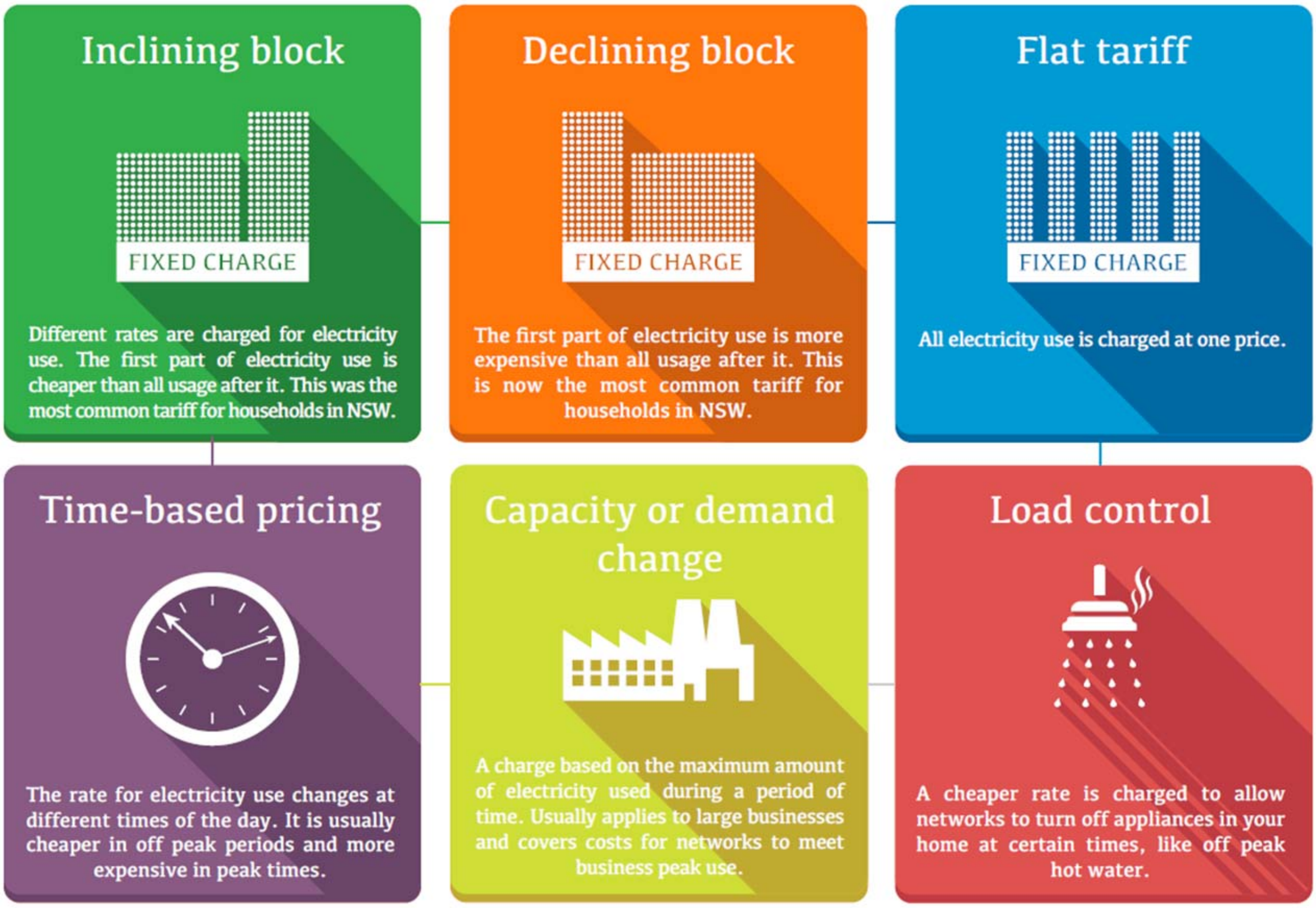
As part of its notification procedures, Essential Energy advises the Retailer that they can request further information from Essential Energy and that they may object to the tariff reassignment decision made. The objection procedure allows Retailers to formally request a review of the tariff reassignment decision. Should the customer or Retailer not be satisfied with the response from Essential Energy, they may escalate the matter to the Energy and Water Ombudsman (NSW) or any other relevant external dispute resolution body to the extent it has jurisdiction over such matters. If the customer or Retailer is still not satisfied with the external party's assessment, they can seek a decision from the AER using the dispute resolution process available under Part 10 of the NEL.

The full details of Essential Energy's policy and procedures for assigning and reassigning customers to tariffs can be found at Attachment 6 to this TSS.

3.5.7 Different tariff types

There are six ways of charging customers for the electricity they use. These are summarised in Figure 3-3 below. Whilst load control is shown as a separate tariff, it also has a flat tariff structure.

Figure 3-3: Ways of charging for electricity use



However, not all tariff types are available to all customers - the type of meter a customer has is the biggest determinant in the types of tariffs that we can offer. As mentioned in section 3.5.5, most of our customers have basic accumulation meters. This limits the tariff options to just four as shown in Figure 3-4 below:

Figure 3-4: Tariff types and minimum metering requirements

	Minimum meter type
Block tariffs	Type 5 or 6
Flat tariffs / Controlled Load	Type 5 or 6
Time of Use tariffs	Type 5 or 6*
Capacity tariffs	Interval or smart meter
Demand tariffs	Interval or smart meter

* Must be programmed for Time of Use

3.5.8 Existing tariff structures

An overview of our existing tariffs and their associated structures is shown in Table 3-3 below.

Table 3-3: Overview of our existing tariff classes and tariff structures

Tariff Class	Associated tariffs	Tariff structure		
		Fixed charge	**Energy charge**	**Demand charge**
Low voltage energy	Residential declining block	✓	✓	
	Residential Time of Use	✓	✓	
	Controlled load 1	✓	✓	
	Controlled load 2	✓	✓	
	Business declining block	✓	✓	
	Business Time of Use	✓	✓	
Low voltage demand	Low voltage – Time of Use average daily demand	✓	✓	✓
	Low voltage – Time of Use three rate demand	✓	✓	✓
	Low voltage – Time of Use demand alternative	✓	✓	✓
High voltage demand	High voltage – Time of Use average daily demand	✓	✓	✓
	High voltage – Time of Use monthly demand	✓	✓	✓
Subtransmission	Subtransmission - three rate demand	✓	✓	✓
	Site specific – unique to each customer	Various	Various	Various
Unmetered	LV unmetered NUOS	✓	✓	
	LV Public street lighting Time of Use		✓	
Inter distributor transfer	Site specific – unique to each customer	Various	Various	Various

4. THE NEED FOR TARIFF REFORM

The reasons why we are implementing tariff changes can be summarised into four broad categories:

1. Improve alignment of tariffs to actual network cost drivers
2. Improve network utilisation
3. Facilitate technology changes
4. Comply with Government policies and regulations.

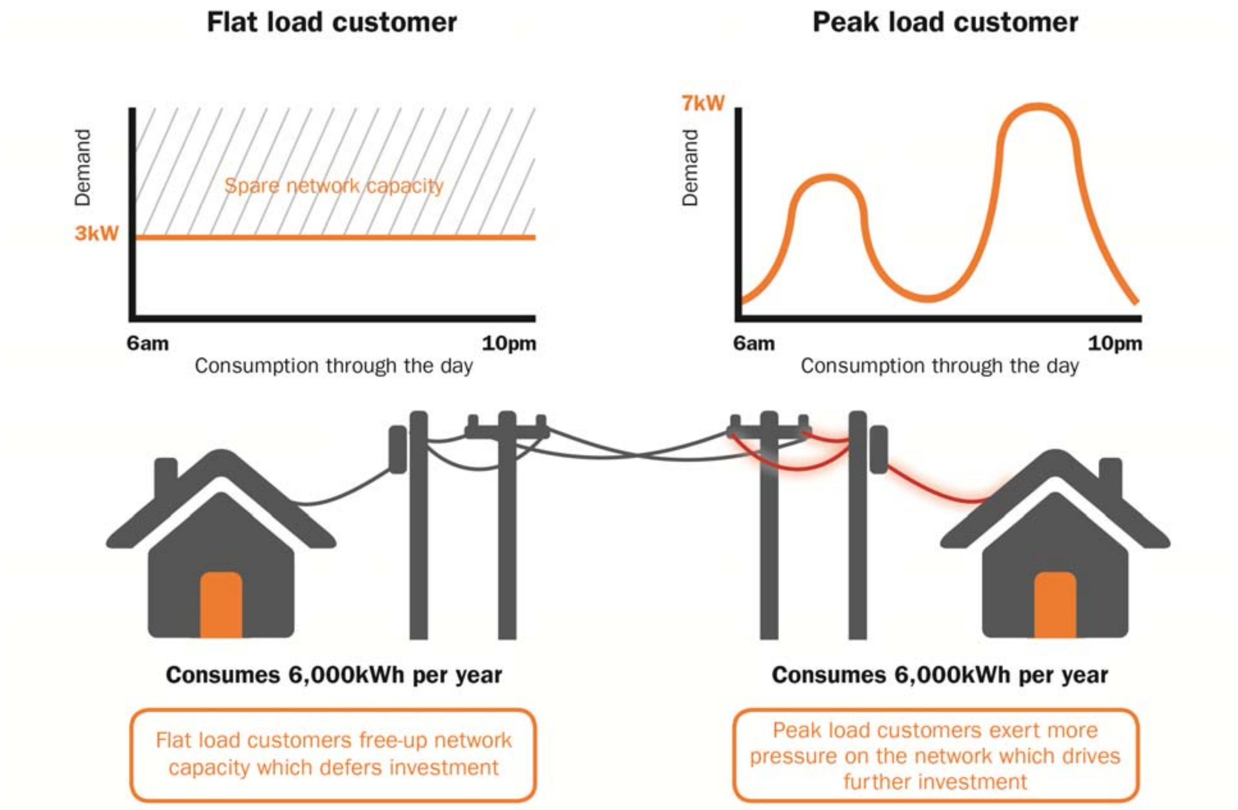
4.1 Alignment of tariffs to network cost drivers

Our network costs are largely fixed but, in comparison, the fixed charge component of our tariffs is quite low and does not fully recover the fixed costs of owning and operating our network. This means that when prices are compared to our actual network costs, most of our customers are paying more in electricity usage charges, but less in fixed charges than they should be.

Presently, most of Essential Energy's customers are charged for each kilowatt hour of electricity they use, regardless of what time of the day they demand it. This means that customers who use electricity more evenly throughout the day and night are, in effect, subsidising the true network costs of customers who use most of their electricity in periods of peak demand.

Figure 4-1 below indicates how two consumers can currently consume the same amount of power, and therefore pay the same network charges, but their impact on the network can be very different.

Figure 4-1: Consumers can place very different pressures on the network



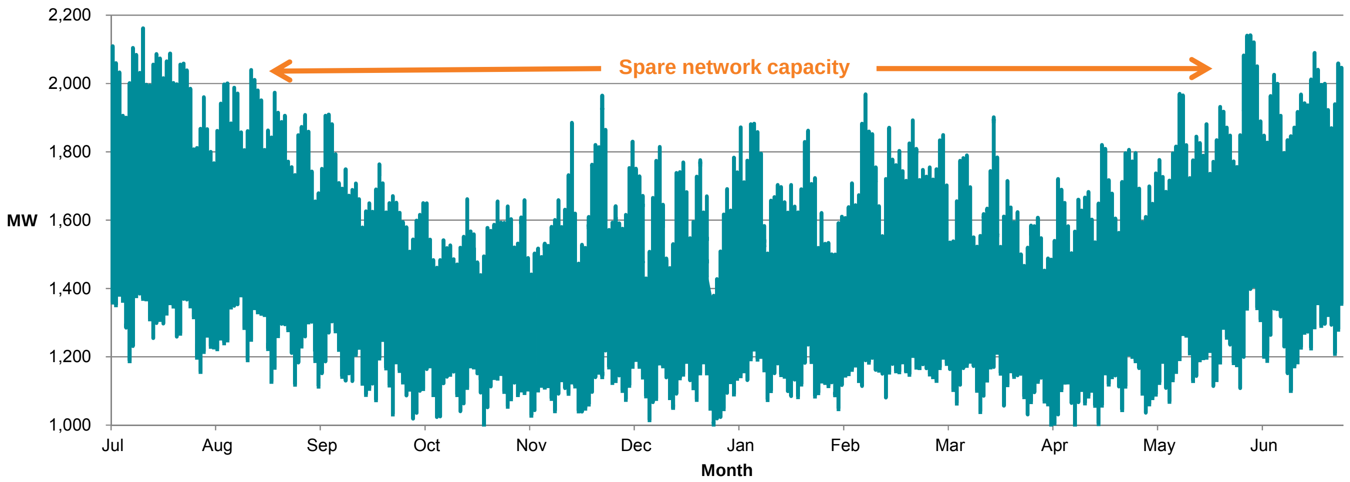
Peak load customers put additional pressure on our network capacity, which would likely lead to the need for additional investment to cater for demand spikes. Flat load customers do not place undue pressure on the network at peak times and consume electricity fairly evenly throughout the day. This type of behaviour makes better (more efficient) use of our network assets.

Cost reflective tariffs help inform customers of their network usage and provide them with the opportunity to reduce their consumption at times of higher network load.

4.2 Consumption levels and network under-utilisation

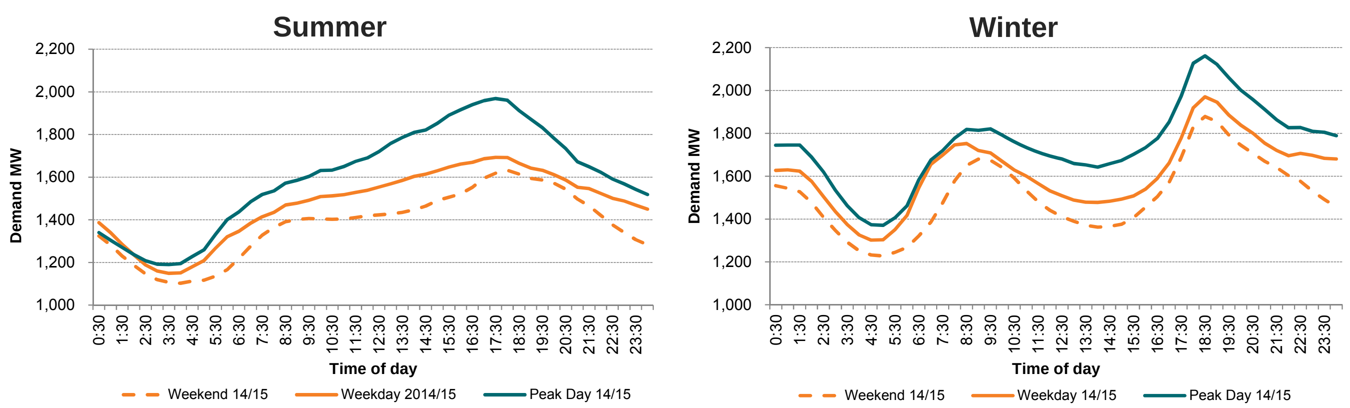
Customers expect electricity to flow whenever they require it, especially on hot summer days when they want to run their air conditioner and on cold winter days when heating is required. Essential Energy's network is necessarily built to safely and reliably supply the maximum demand for electricity that customers require – the peak load. However, the peak load is required for only a handful of days each year, as shown in Figure 4-2 below.

Figure 4-2: Network load profile 1 July 2014 to 30 June 2015



The *average daily load* on our network is much lower and there are significantly different profiles between an average summer's day and an average winter's day. This is shown in Figure 4-3 below.

Figure 4-3: Average daily summer and winter network load 2014-15



Demand tends to increase slowly over a summer's day, while there is a morning peak followed by an even greater evening peak in winter.

However, Essential Energy must provide a network capable of meeting these peak loads and this means that, for most of the hours in a day (and for most days of the year); our network assets are largely under-utilised. Figure 4-3 above indicates that average daily consumption in 2014-15 was about 250MW below the peak day demand shown in Figure 4-2.

Instead of continually augmenting the network to meet demand as the population continues to grow and we become ever more reliant on electronic technology, the far more efficient and cost-effective solution is to reduce the peak load spikes and smooth average daily consumption to make better use of the existing network assets. This will defer, or even avoid, additional costly augmentation works and, in turn, reduce the pressure of increasing network prices. It also makes sense to encourage consumers to use electricity during times when the network has spare capacity.

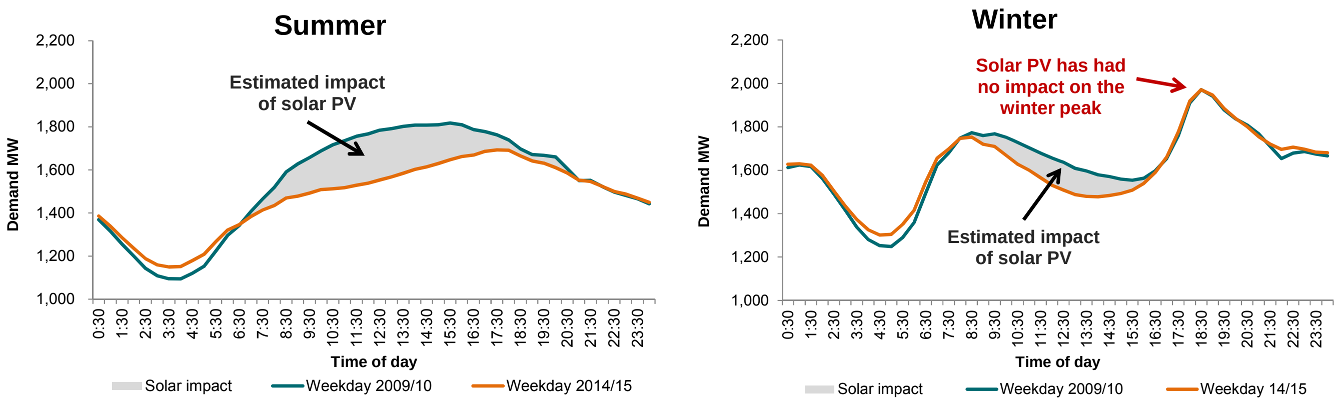
4.3 New and improving technologies

4.3.1 Solar PV and battery storage

Today's customers want more control over their electricity bills. This is evident from the responses to price rises over the last few years, as well as the continued take up of solar PV units (though at a slower pace since the cessation of generous government incentives for solar rebates). Many generous government feed-in-tariffs continue to provide substantial on-going payments to many solar PV customers, regardless of their consumption patterns.

Not surprisingly, solar PV has reduced electricity consumption from our network, particularly in summer. It has, however, had no impact on winter peak demand. This is shown in Figure 4-4 below. Almost 15 per cent of our customers have solar PV, and in 2014-15, our average daily demand was lower during the middle of the day when compared to 2009-10, but the evening peaks have not altered significantly. Analysis has shown that this is largely due to solar PV penetration.

Figure 4-4: The impact of solar PV on average daily demand (2009-10 versus 2014-15)



As mentioned above, the fixed component of our current tariff structures is too low and does not accurately reflect the true cost of being connected to our network. This means that our consumption charges are too high, giving an inflated financial gain to those customers who are able to make use of solar PV to lower their consumption at the expense of customers who can't afford to invest in the technology, or are unable to make use of it as they are renters or live in an apartment block.

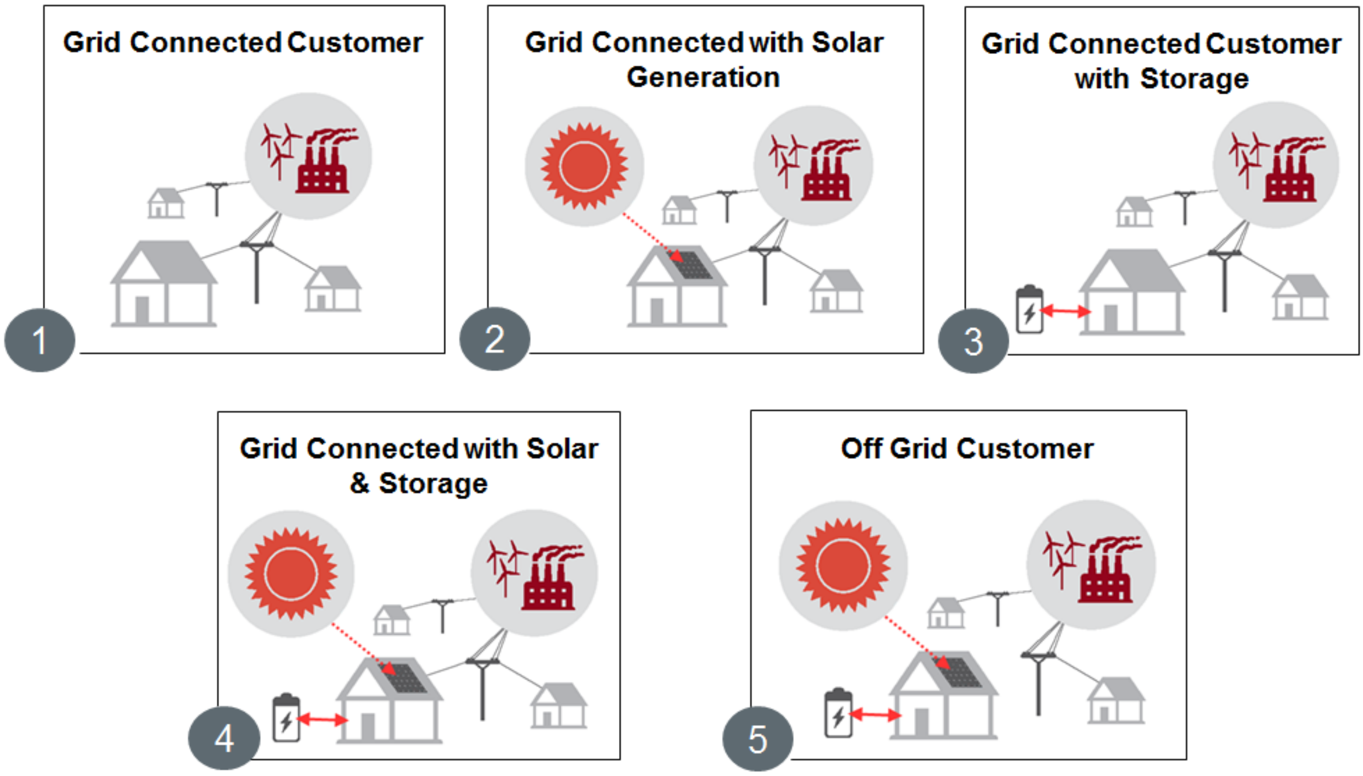
Some customers with solar PV are going 'off-grid', meaning they are no longer connected to our network at all. Others are 'partially off-grid', remaining connected to the network but only using the network as a back-up or when their demand for electricity exceeds their own supply. It is anticipated that there will be more customers in the future taking up these options.

We do not want customers to leave the grid, as this leaves fewer and fewer customers to pay for the network – generally, those who can least afford it, and this will further exacerbate the under-utilisation of our existing network assets. While, at this stage, becoming an off-grid customer is an extremely costly exercise, advances in battery and solar PV technology will make this more affordable and will create additional challenges for our existing network model and tariff structures.

The electricity supply choices that solar PV and battery storage offers customers are shown in Figure 4-5 below. Whilst historically everyone was connected to the network in the same way, solar and battery storage have created four other supply options for customers.

Although we are not introducing a solar tariff for this TSS it is something that we will be closely monitoring in the future.

Figure 4-5: Customer choices for electricity supply utilising emerging technologies



4.3.2 Electric vehicles

Electric vehicle technology is improving – batteries are becoming larger and rapid charging equipment is being developed. As these vehicles become more affordable and can be charged from a regular power point, we would expect to see pockets of increased demand in some areas of our network, especially if owners expect to charge their vehicles immediately after they arrive home from work in the evening.

We need to consider this growing technology when developing our tariffs to ensure we will be ready to send electric vehicle owners' efficient price signals and encourage them to shift their load to off-peak periods where there is spare capacity on the network.

4.3.3 Smart meters and demand management technology

Smart Meters benefit consumers by providing clear real-time price signals about their electricity usage, empowering them with the necessary data to seek competitive electricity retail offers. Smart Meters can work with demand management devices to automate electricity management for customers. Demand management devices can be programmed to automatically shut off non-critical appliances, such as a pool filter, or to cycle appliances such as an air-conditioner or refrigerator, on and off in periods of high demand.

Smart Meters also provide Essential Energy with a better understanding of how our customers use electricity. This helps us better design tariffs and tariff structures to reward customers whose consumption patterns help to minimise our network costs.

However, unlike Victoria, where the government has undertaken a mass roll out of Smart Meters, most NSW households and small businesses have basic accumulation meters. These meters measure the total amount of electricity used over a period, but provide no detail about what time of day the electricity was used or how much demand was placed on the network at any given time. Without Smart Meters, or even an Interval meter, most NSW customers lack the ability to make truly informed choices about their electricity use.

In NSW we cannot force customers to change their meters, but it is important for customers to know that they can elect to change their meter at any time. For customers with a flat demand profile, and those who can move a large amount of their electricity consumption away from daily peak times, a Time of Use capable meter, an Interval meter or a Smart Meter, combined with the appropriate tariff, may save them many dollars on their electricity bill.

The different types of meters are discussed in more detail in section 3.5.5.

4.3.4 Virtual net metering

Virtual net metering (VNM), also known as peer to peer trading, is being trialled in most states across Australia in a program run by The Institute for Sustainable Futures and is the subject of a proposed Rule change. Essential Energy is part of this program and is currently undertaking a trial of virtual net metering with Byron Bay Shire Council. In this trial, excess energy from the large solar PV installation on the Council's sports centre will be credited to the neighbouring sewage plant, which does not have sufficient roof space for a solar array, but has high energy needs.

VNM requires a Smart Meter and an on-site electricity generating source (for example, solar PV). With this equipment, a customer can transfer any excess electricity they produce to another nearby consumer. It is envisaged that customers may be able to set their buy and sell rates for energy via an online portal. When combined with battery storage, technology also exists that would enable energy to be stored on-site and sold back to the market when the electricity price is high.

Rather than looking to move off-grid, VNM encourages self-generators to stay connected to the network, as they stand to make a better financial return on their generated energy. Currently, any excess on-site generation must be stored in a battery or sold back to the grid at a price (set by the Retailer) that is generally much lower than the price at which the electricity is sold to other consumers from the network.

As mentioned in section 4.3.1 above, we want customers to stay connected to the grid, not only to better utilise existing network assets, but also to share the associated network costs between as many customers as possible.

4.4 Government policies and regulations

Regulation at both a Federal and State level impact our tariff setting. New markets and technologies are challenging the current regulatory landscape and we expect continuing developments in this area.

Regulatory changes have also driven an increasing focus on customer consultation throughout the regulatory process, including in the development of our TSS. Our customer and stakeholder engagement process is discussed in section 5.

4.5 Impact on customer prices and tariffs

The costs of running and maintaining our network are mostly fixed, yet most of our current revenue is coming from the variable component of our tariffs. This means that our current tariffs structures are not providing efficient price signals for customers and could discourage efficient utilisation of the network, contrary to the new Rule.

Coupled with advancing technology developments, this would place increasing demand pressure on our network and allow home owners with disposable income to invest in technology that will see them avoid paying much of the real fixed costs required to service their network connection, at the expense of customers who can't afford to invest in technology (lower income customers) or can't access technology (renters and high density unit dwellers).

Instead, we need to structure our tariffs to provide long-term benefits to our customers through:

- Better aligning our tariffs to our cost drivers so that customers pay a price that more accurately reflects the efficient costs of the network services we provide;
- Influencing customer consumption behaviour in a way that encourages better utilisation of our existing network to ensure augmentation only takes place where it is truly efficient to do so; and
- Encouraging customers to remain connected to the network.

Our proposed tariff structures, outlined in this TSS, fulfil these requirements.

5. ENGAGING OUR CUSTOMERS AND STAKEHOLDERS

Essential Energy's network area spans regional cities, rural farmland and remote rural locations. Understanding the composition of our customer base is critical to meeting the diverse connection, consumption and billing needs of both individual customers and customer groups.

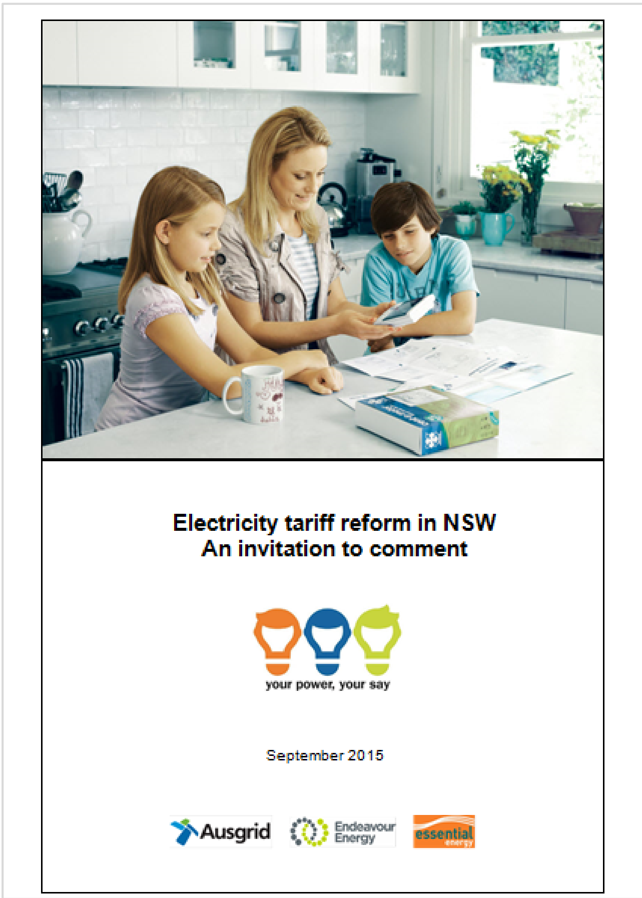
This section explains how we have engaged with customers and stakeholders and taken their feedback into consideration in developing our tariff structures.

5.1 Engagement principles and approach

Customer engagement is a key aspect of Essential Energy's business. We have been engaging with customers for many years now. Our customer engagement principles are outlined below.

Figure 5-1: Our customer engagement principles

- Candid, respectful, open and honest
- Remove barriers to participation
- Be proactive rather than reactive
- Timely and accurate information
- Learn from previous engagement and continue to improve performance
- Develop strong and open relationships to build shared understanding
- Explain how community views were addressed and be clear when/why we couldn't use them



We began undertaking tariff reforms based on customer feedback in July 2013. At this time, we proposed moving from flat rate tariffs to declining block tariffs for two of our most common residential and small business tariffs.

In September 2015, we invited customer comments on our tariffs with the publication of our Issues Paper – 'Electricity tariff reform in NSW – An invitation to comment' (see Attachment 8 to this TSS) and a fresh round of media advertisements. Customers were able to respond via a number of channels including through our own website, email, phone or the NSW government 'haveyoursay' website. Formal written submissions were also encouraged.

In conjunction with Networks NSW we also facilitated targeted roundtable discussions with several key stakeholder groups, including vulnerable customers, Retailers, Food & Fibre customers and environmental groups. We also sent letters to accredited service providers and councils in our network area.

We were keen to explore opinions, insights and evidence about tariff options, including the existing declining block tariff now managed across all network businesses in NSW. We found there was considerable appetite among consumer and environment stakeholders to understand the economic, financial and regulatory aspects of proposed network tariff changes in the two years from 2017 – 2019.

Our stakeholder engagement strategy is discussed in more detail in Attachment 9 to this TSS.

Our Issues Paper asked customers for specific feedback on the following areas highlighted in Figure 5-2 below:

Figure 5-2: What we asked our customers and stakeholders

WHAT WE ASKED OUR CUSTOMERS AND STAKEHOLDERS

2015

DECLINING BLOCK TARIFFS

> Do you support declining block tariffs?

> Are they more effective at preventing "bill shock" than other alternatives?

CUSTOMERS WHO GENERATE ELECTRICITY

> What tariffs / charges should apply to recover the network costs for customers who export electricity to the grid?

FOOD AND FIBRE TARIFF

> What do you think of a specific tariff for these groups?

> Should a tariff be set at an efficient level if it means higher charges at peak times?

ANCILLARY NETWORK SERVICES, METERING SERVICES AND STREET LIGHTING

> What are the main issues for these pricing structures?

SOCIAL TARIFFS

> Should we have social tariffs for vulnerable customers?

> How should they be structured, funded, and applied?

> Who is the best body to provide this service?

TIME OF USE TARIFF

> Do you like time of use tariffs?

> Why do you think their take up is so low?

> Are there other voluntary tariffs of interest to customers?

REGIONAL PRICING

> Are location-based tariffs acceptable?

> In what situations should they apply?

> Are you happy to pay a higher administration cost for this structure?

DEMAND TARIFF

> Should demand tariffs apply?

> How could they be structured?

> Who should pay for the associated metering costs?

> Will they lower future network costs?

> Over what time period should we transition to this structure?

TRANSITIONING TO MORE EFFICIENT OUTCOME TARIFFS

> How would you like to transition to more efficient tariffs?

> Should increases be capped?

5.2 Key messages from our customers and stakeholders

This TSS incorporates the feedback from all customer and stakeholder sources as well as providing explanations where comments have not been taken on board at this time.

On the whole, our customers want tariffs to encourage a low cost, reliable supply that does not discourage or create disincentives for customers to install alternative power sources, such as solar PV or battery storage. They also want tariffs to be designed to support energy conservation and efficiency, for example by encouraging customers to turn off of non-essential appliances or allow them to shift less important appliances to off-peak times under a Time of Use tariff.

There was also an awareness of technological developments and future market roles, for example Virtual Net Metering which allows generation at one site to be transferred or sold to another nearby site at a lower network charge. Our customers thought these advancing markets would encourage customers to stay connected to our network.

The key themes and messages from our customers and stakeholders are shown in Figure 5-3 below. A full record of all stakeholder engagement undertaken and the issues raised can be found in Attachment 3 – *Stakeholder engagement report from Acil* Allen to this TSS.

Figure 5-3: What our customers and stakeholders have to say

5.3 How we have considered customer and stakeholder feedback

Our customer and stakeholder feedback has informed much of our proposed tariff structures. Some specific feedback items that have been addressed in our tariff structures are:

> Key elements of our proposed tariff structures for residential and small business customers are aligned with other NSW distributors;

> Our tariff structures are simple and easy to understand;

> We will transition customers to our proposed efficient price structures to minimise price shock;

> We are proposing different prices for our peak and shoulder tariffs;

> We are not proposing location based tariffs;

> We are not proposing any Food and Fibre tariffs;

> We are not proposing any social tariffs; and

> We are not proposing new tariffs for customers who export electricity to the network.

More discussion on some of these themes, as well as the other areas of feedback we received, is detailed in the following sections.

5.3.1 Tariff structures that are simple and easy to understand

Our proposed tariff structures are consistent with our current structures (see section 6.3) which will make them easier for our customers to understand, than if we were to introduce new structures.

Our engagement process has highlighted, however, that many of our customers do not have an awareness of the alternative tariffs we offer. We hope that this tariff structure statement will outline, at a high level, the tariffs we offer. We are also in the process of creating brochures explaining how Time of Use tariffs work (a specific customer feedback request - see section 5.3.6), how Controlled Load tariffs operate (also suggested by our customers – see section 5.3.14) and the functionality of the different types of electricity meters available to customers and how they are aligned to tariffs. These will all be published on the Electricity Network Pricing section of our website by June 2016 so they can be easily accessed by our customers.

Another message that was clear from the feedback we received was that customers do not know that they should confirm with their Retailer that they are on the most suitable tariff and to enquire whether there may be a better tariff option if they are willing to pay for an electricity meter upgrade.

It is important for customers to engage with their Retailer, particularly at the end of a contract period, to ensure they remain on an appropriate and competitive tariff. This is particularly important in the light of a recent St Vincent de Paul Society report (Vinnie's report) titled "The National Energy Market – Still winging it"[2] which found that standing Retail offers were often considerably higher than the market offers that can be obtained by customers shopping around (as they usually offer high pay-on-time discounts).

The Vinnie's report found the estimated Retail cost of standing offers to be significantly higher in deregulated Retail markets and questioned whether competitive markets are just very expensive, very ineffective [3] or that standing offer customers are subsidising market offer customers[4]. The Vinnie's report also raised concerns that the price spread between standing and market offers has been increasing, along with the difference between the best and worst market offer available to customers[5].

We stress to our customers that their electricity contract is with the Retailer and not ourselves. Unfortunately, the current Retail market seems to require customers to continually switch to the best market offer available once their contract expires, penalising those customers that for any number of reasons are unwilling and/or unable to move Retailers.

5.3.2 Customer transition to cost reflective tariffs

Feedback indicated a timeline transition of at least 24 months with a preference for three to five years. Some feedback was supportive of price rises being capped at CPI, other feedback saw this hampering the path to cost reflectivity as it would have an impact on other network charges and revenue recovery.

We have taken this on board in developing our transition plan outlined in section 6.5. Our transition period will minimise the impact of price changes for our customers over a longer term than this TSS, having regard to the Rule requirement to take customer impacts into consideration.

5.3.3 Location based tariffs

We asked our customers and stakeholders whether they thought tariffs should be set on a locational basis to reflect higher or lower costs or big swings in low and high demand. The messages we received were:

- Electricity is an essential service, it is unfair to disadvantage customers simply because of their location on the network;
- These would greatly impact vulnerable communities and those susceptible to intermittent vulnerability, for example farming communities during a drought;
- If the cross subsidy between urban and rural customers was fully removed, rural customers would not be able to afford grid based electricity;
- We would need to see very detailed proposals and customer impact analysis;
- They would only be good if they were used to incentivise, rather than penalise customers; and
- They would be acceptable if they supported the use of local energy generation by allowing prosumers to export electricity to consumers in the local network and have the consumer receive no TUOS charges and reduced DUOS charges.

Section 5.3.16 deals with the concept of virtual net metering raised in the last of these points.

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[2] St Vincent de Paul Society & Alviss Consulting, *The National Energy Market – Still winging it*, September 2015

[3] Ibid p.19

[4] Ibid p.20

[5] Ibid 26

For the reasons put forward by our customers and stakeholders, we are not proposing any location based tariffs in this TSS.

5.3.4 Social tariffs

Our customers and stakeholders were concerned about electricity prices and their impact on vulnerable customers. It was recognised that increasing the fixed charge component of a bill (and lowering variable charges) will have a greater negative impact on low income households.

On the whole, our customers and stakeholders did not think that a social tariff funded by other customers was a good thing as a “one size fits all approach” would be unlikely to deliver the desired outcomes. It was also thought that such a tariff would mean the working poor (customers who are just one or two pay cheques from falling into poverty) would be worse off through higher electricity charges.

It was acknowledged that the network component is just one part of the total electricity price customers pay – as such, whilst a social tariff is generally considered to be a good idea, it is unclear who should be responsible for managing it – the network, the Retailer or the Government. As such, feedback supported the continuation of low income rebates and assistance being administered by the Government. This is a theme we will continue to revisit in future TSS periods.

5.3.5 Export tariffs

We asked whether customers who generate their own electricity and export it to the network should pay a tariff - recognising their use of network infrastructure in doing so. Overwhelmingly, our customers and stakeholders did not consider this to be appropriate. Opinions included:

- Customers had invested to save money, not pay a premium;
- Consumers of electricity should pay network charges, not generators;
- Network charges should be designed to address the economic and physical optimisation of the network in a technology neutral way;
- Locally generated electricity should “cost less” to the network than power plant generated electricity;
- On-site consumption and export to the grid reduces network demand peaks, so such a tariff would directly oppose cost-reflectivity;
- Surely the administrative costs of such a tariff would outweigh any perceived benefit;
- Encouraging generating premises to use the energy on site or invest in batteries to ease peak demand pressures would lead to a better outcome;
- Separate prices would deter the take-up of these products which could increase network capacity requirements;
- Houses with air-conditioners benefit from greater cross-subsidies than solar PV sites;
- Such a charge would contradict 6.18.4.(3) of the NER that “retail customers with micro-generation facilities should be treated no less favourably than retail customers without such facilities, but with a similar load profile”;
- Such a tariff would clash with the proposed Rule change request before the AEMC in relation to Local Generation Network Credits;
- Such a tariff would further encourage such generators to move off-grid which is something networks are specifically trying to avoid.

We have taken on board this feedback from our customers and stakeholders and we are not putting forward any export tariffs as part of this TSS. However, this is an area that will be closely monitored, and we may introduce some form of solar tariff in the next TSS period.

5.3.6 Time of Use tariffs

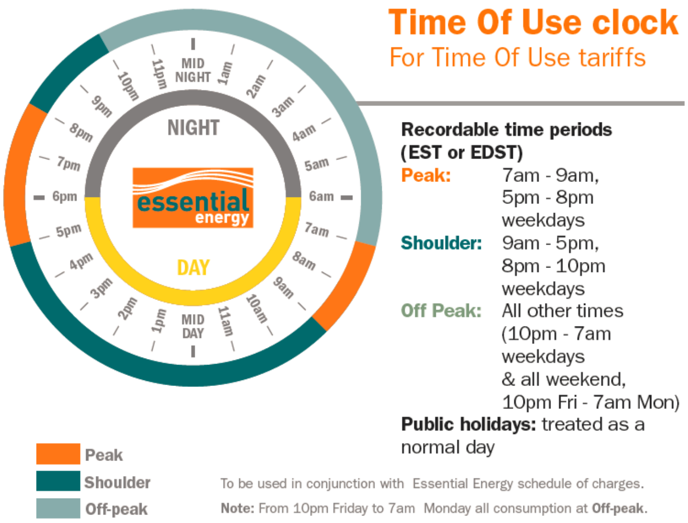
Time of Use (TOU) tariffs offer three different pricing periods: peak; shoulder; and off peak. They can allow customers to make decisions on when to cost effectively use power.

Time of Use tariffs are poorly explained to residential and small business customers

Feedback indicates that some residential and small business customers may not fully understand how TOU tariffs work and how they may be able to benefit from them. TOU tariffs require customers to have (at a minimum) a TOU capable meter so customers without such a meter would be required to pay a meter change fee (see the Metering Service Charge page in Attachment 7 - *Alternative Control Pricing Schedule* to our TSS).

As mentioned in section 4.3.3 we cannot force customers to change their meter, but it is important for customers to know that they can elect to change their meter at any time. For customers who can move a lot of their electricity consumption away from the daily peak times, a TOU capable, Interval or Smart Meter combined with the appropriate TOU tariff may save them many dollars on their electricity bill. We encourage our customers to contact their Retailer to discuss the best tariff for them.

In the meantime, we have taken this feedback on board and will develop a TOU Tariff brochure specifically for residential and small business customers (similar to our Demand Tariffs brochure for businesses). This will be made available by June 2016.



TOU tariffs do not recognise public holidays that fall on a weekday.

Queries were raised as to why public holidays that fall on a weekday do not have an off-peak tariff applied to them, given demand would more likely resemble that on a weekend.

This occurrence is the result of the current metering technology in place around our network. The bulk of our TOU meters are Type 5 or Type 6 TOU capable accumulation meters. To accommodate this request, each meter would need to be manually adjusted every year to take into account the changing days of the week on which public holidays occur. This would not be a cost effective exercise for our customers especially when, for our business customers at least, most would be closed on public holidays and using little electricity anyway.

With technology improvements in Smart Meter technology, this is something that will be possible in the future. The ability to share data between the network and Smart Meters would allow public holiday events to be automatically downloaded to every meter on the network with minimal effort and, more importantly, at little cost.

We are, however, now looking to change this for customers with Interval meters (Type 1 – 4) so that public holidays are charged at weekend (off-peak) rates. If this change can be implemented cost efficiently, we will introduce it prior to 1 July 2017 and ensure such a change is well advertised to our customers.

TOU tariff periods do not necessarily align to Retail TOU tariff periods, especially during daylight savings

It was suggested that we align our TOU time periods to that used by the Retailer. Unfortunately, this is just not possible.

Our TOU periods are designed around the demand on our network and, in accordance with the Rules, reflect the efficient costs of our provision of network services to our customers. We do apply daylight savings time to all customers with Interval meters in determining network charges, but all other TOU customers have summer time applied. As above, this is due to the type of meters we have in our network and the fact they would require manual adjustment for the changes in daylight savings dates.

We charge our tariffs to the Retailer who is then responsible for setting their own tariffs to recover not only our charges, but also their own costs and profit margin. As customers contract with Retailers, and not us, this may lead to discrepancies between TOU periods.

For customers with Type 5 and 6 meters, Essential Energy is responsible for reading the meters and this means that Retailers use the same readings and are forced to adopt our time periods. So for most small customers the time periods are aligned with Retailer’s time periods, however this may change in the future as more customers install alternate meters.

We would suggest that customers with this concern, voice their discontent to their Retailer to try and encourage them to align their TOU periods (which are not subject to the Rules requiring efficient price signals) to ours.

Shoulder and peak tariff pricing

Customers queried why peak and shoulder prices for our TOU tariffs are the same. This has been due to the fact that in the past peak demand on our network has been experienced equally between these two time periods, meaning peak demand was put on our network as often in peak times as in shoulder times. As such, our tariff rates for the two periods were set at the same price to reflect the true cost of demand on our network.

We have started to see the evidence of a peak demand shift and have therefore decided to apply different charges to peak and shoulder periods from 1 July 2016. These will apply to both the energy and demand charge components.

5.3.7 Demand tariffs

Some of our customer groups requested demand charge tariffs for small customers, however, at this stage we are not introducing this tariff structure. This is due to the fact that we do not have enough data available to be able to price a demand charge accurately.

Demand charges are applied to either a customer’s electricity capacity requirement ($/kVA) or their maximum demand level ($/kW). They are best applied when the associated charges correlate with peak network demand.

This tariff would require customers to have an awareness of the maximum demand they use at any one time. We don’t believe that most of our customers would have this knowledge and the prevalence of Type 5 and 6 meters in our network area means they are unable to gain that understanding (we have a total of 1,453,047 Type 5 and 6 meters in our network area as at 30 June 2015) without investing in new interval meters.

Demand charges require an Interval meter or, to be truly effective, a Smart Meter preferably with an automation device to help customers actually reduce the amount of electricity used. For us to implement demand charging, we would firstly need customers to pay for their meter to be changed. This fact was also recognised through the feedback we received:

> “…*the tariff reform process is largely influenced by individual customer metering capability and access to interval consumption. In this regard, we consider Networks NSW has adopted a pragmatic and sensible approach to implementing tariff reform. … we also recognise that a considerable number of residential customers will remain on accumulation meters for the next five years. As a result, this is a constraint on the rate at which tariff reform can progress”*[6]

The Victorian Government has progressively rolled out Smart Meters to most Victorian premises and the Victorian distributors have put forward tariff structures that are moving to demand charging. We will closely monitor the impact that these tariffs have on Victorian network demand to see if customers actually change their usage behaviour, with the subsequent flow on effect of reducing network costs.

A recent CSIRO research paper titled “Australian Consumers’ Likely response to Cost-Reflective Electricity Pricing” (the CSIRO Study - Attachment 10 to this TSS) found that consumers find all forms of cost-reflective pricing significantly less attractive than traditional flat rate tariffs and *they are especially resistant to demand charging* (called capacity pricing in the document), most likely due to its greater complexity and perceived risk[7].

An example of this risk was highlighted in our customer feedback where a customer, who is currently on a tariff with a demand component, expressed surprise at being penalised due to an outlying peak reached only once during a billing period. They thought that demand should be calculated on a more persistent level. This, however, is just not the nature of a demand tariff which necessarily penalises customers who demand a high level of energy, even if it is just once in a billing period.

The CSIRO study also found that:

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[6] Origin, *Response to NNSW Issues Paper*, October 2015

[7] CSIRO, *Australian Consumers’ Likely Response to Cost-Reflective Electricity Pricing*, June 2015 p.5

> "*Cost-reflective pricing will be more successful the less it relies on consumers, themselves, responding to changing price signals.*" [8]

They contend that the collective problem is not around getting consumers to take up or even use cost reflective pricing, but how best to reduce peak demand in a manner that will yield benefits to consumers and networks alike. CSIRO found that international experience suggests that cost-reflective tariffs are unlikely to yield the desired benefits without an appropriate suite of supportive mechanisms to facilitate their optimal usage.[9]

We also received feedback asking why, given that the network is largely under-utilised, demand charges for residential and small business would be necessary, as well as some recognition of the complexity of demand tariffs for customers:

> *"… the most economically efficient tariff may not always deliver an optimal outcome simply because the customer does not understand the signal and therefore how to respond. Conversely, tariff solutions that are perceived as second best may actually deliver better network outcomes because they are simpler and easier to understand and therefore they generate the intended customer response. … In our experience, the majority of networks are attracted to demand based tariffs as they consider these best signal the costs of operating the network at times of greatest utilisation. However, we believe demand based tariffs are just one approach that fall within a spectrum of acceptable methods, especially given the constraint of metering."*[10]

Another concern is a lack of reliable data. Our metering devices mean we only have *accumulated* historical data for the majority of our small customers – we have extremely limited data on their *demand* usage. As such, we do not have a reliable base for setting the rates for a demand tariff and it would be difficult to develop prices that appropriately met the Rule criteria, even under an opt-in basis.

The results of the CSIRO Study, combined with our existing metering technology, lack of reliable data and view that many customers do not really understand demand charging, supports our 'wait and see' position. Whilst we are not presently considering demand tariffs for the bulk of our customers, it is something we will revisit, in conjunction with our customers and stakeholders, for the next regulatory period.

5.3.8 Low demand sites pay disproportionate transmission and network costs

At certain very small sites where electrical supply is only used for low amperage supply, for example batteries associated with SCADA systems, the electricity account is predominantly composed of transmission and network costs with a very small electrical energy cost component. It was suggested that a special network tariff could be applied to such low load sites on the basis that they do not exert much pressure on the distribution network.

Unfortunately, as discussed in section 3.2, our network costs are predominantly driven by the number and condition of our assets coupled with the size of our network area. This means that most of our network costs are largely fixed, regardless of customer demand, so the fixed component of our network charges is necessarily high, especially compared to what an urban electricity distributor would charge.

We suggest that affected customers contact their Retailer to discuss their metering and tariff options to ensure they are on the most appropriate tariff.

5.3.9 Seasonal variations in demand

Our current demand charges do not recognise seasonal variations in demand. It was suggested that tariffs should reflect seasonal variability.

We experience variability in peaks across our network, with some areas peaking in winter and some in summer (see *Figure 2-4: Our areas of expected network growth* in section 2.5.8). As a result, we are not looking at introducing seasonal based peak demand tariffs at this stage. It is, however, an area we will continue to monitor and consider in future TSS periods.

[8] Ibid p.9

[9] Ibid

[10] Origin, Op cit

5.3.10 Declining block tariffs versus inclining block tariffs and flat tariff structures

Retailers generally supported declining block tariffs (DBTs) while other stakeholders did not support this tariff structure as they generally felt it was a poor incentive to use electricity efficiently. The major feedback themes and our associated responses are provided below.

DBTs are not correlated with peak demand

Many stakeholders questioned how DBTs can be cost reflective, given they apply at any time of the day or night and bear no relationship to peak demand. It was thought they actually create an incentive to use more energy during peak periods, which will lead to higher demand peaks and eventually increased capex and opex requirements.

Given the overwhelming number of basic accumulation meters installed within our network, we are extremely limited in the types of tariffs that we can offer (see section 3.5.5). When coupled with the predominantly fixed cost nature of our operations, DBTs are the most suitable tariff structure option to ensure efficient price signals for customers.

Retailers will discriminate against low energy users

Retailers were generally supportive of DBTs. Other feedback, however, thought DBTs provide an incentive for Retailers to favour customers with higher demand, leading to less competitive retail products being offered for low energy users. Other feedback indicated that DBTs have not been replicated by Retailers who have instead maintained inclining block structures and pocketed the difference as profit.

Retailers are not obliged to pass on any of the price signals (tariffs) we implement in the same form to their customers. Therefore, we encourage customers to shop around for the best retail deals. This is especially important in light of the Vinnie's report findings mentioned in section 5.3.1.

Inclining block tariffs are more suitable

It was thought that:

- As our LRMC is actually quite high, perhaps inclining block tariffs would be more suitable than DBTs.
- Compared to inclining block tariffs, DBTs also disadvantage low energy users as they gain the least price relief from this structure, especially if the rate of decline increases
- DBTs are less motivating for customers to reduce their consumption and associated greenhouse gas emissions, compared to an inclining block tariff.

The Rules require us to provide efficient pricing signals, and for our tariffs to be based on LRMC. They must also be placed between the stand alone cost of supplying that customer class and the marginal cost of supplying that customer class – all our proposed tariff structures comply with this Rule requirement.

The economic analysis undertaken by Houston-Kemp has shown that our DBTs are compliant with the Rules, whereas inclining block tariffs would not be. This analysis has also shown that the block rates are all above the LRMC for low voltage customers meaning that some of our residual costs are also being recovered by the usage charges. Refer to Attachment 4 for further detail.

DBTs conflict price efficiency and customer consumption

It was thought that DBTs create a conflict of interest between efficient network pricing and encouraging customer consumption. It was suggested that the best way to reduce bills (and bill shock to customers) is to lower consumption and encourage more efficient energy use, not drop the kWh rates and encourage higher usage.

Our DBTs are compliant with the Rules and as they are based on LRMC they do provide efficient pricing signals. During times of declining consumption and spare capacity on our network, DBTs will help keep customer prices down whilst also providing price stability. Under our revenue cap price regulation if customers use less energy than expected, prices must increase to enable us to recover the same revenue.

DBTs discourage demand side solutions

Some feedback thought DBTs will discourage demand side investment as they lower the return on investment and fail to promote a price signal to undertake demand response and generation in a manner that provides broader benefits. As such, they were considered to be contrary to the principal objectives and functions of energy distributors under the *Energy Services Corporation Act 1995 - Part 3 Energy Distributors.*

DBTs are already in place across the three network businesses in NSW. We are taking a mid-term to long-term view of the steps required to make the transition to efficient tariffs, especially given our existing metering constraints.

Our DBT tariffs will be transitioned over time such that the residual costs will eventually be recovered from the fixed charge and first block, while the second and third blocks will be set to LRMC levels. In this light, a DBT is appropriate for the two years from 2017 – 2019 as part of our transitional arrangements and will cushion most of our customers from 'bill shock by providing price stability'.

5.3.11 Other tariff structures

Given the underutilisation of the network for much of the year, a few stakeholders questioned whether establishing pricing signals to minimise annual peak demand would be a better choice, rather than targeting peak consumption across all months of the year.

Some examples put forward were Critical Peak Pricing, Peak Time Rebate, Real-time Pricing and Variable Peak Pricing. A summary of the features of these tariff types is shown in Table 5-1 below, the bulk of which has been taken directly from Table 1 in the CSIRO Study.

Table 5-1: Features of other suggested tariff types

Tariff type	Features
Critical Peak Pricing	> Customer pays a much higher price (per kWh) for the electricity used on ~15 'critical event days' per annum (when system-wide demand for electricity is highest), but a lower price for the electricity used at all other times of the year. > Critical event days are typically times of 'extreme weather' – in warmer climates, the few hottest days of summer when use of air-conditioning spikes, and in cooler climates, the few coldest days of winter when space heating spikes. > Ordinarily, a utility specifies the maximum number of critical events that can be 'called' in one season. A critical event day is 'called' when high system load is predicted (usually based on weather forecasts). > Customer is notified the day before a critical event / 'extreme temperature' day is going to happen (e.g., via text message, email). [11]
Peak Time Rebate	> Customer pays a flat price for each kWh of electricity used, but they also receive a rebate (money back on bill) on each occasion they use less electricity than normal, during critical events – i.e., on about 15 'extreme temperature' days each year. > The price (cents per kWh) paid for using electricity remains the same regardless of when it is used it (e.g., no matter what time of day, day of the week, season), but the customer earns a rebate each time they used less electricity than normal during the very hottest and/or coldest days each year. > The amount of reduction is usually calculated using a household-specific measure of energy consumption during similar conditions on other days with similar weather patterns. > Customer is notified the day before a critical event / 'extreme temperature' day is going to happen (e.g., via text message, email). > If customer does not use less electricity than normal on critical event days – either because they do not want to, or cannot manage it – they simply pay the normal price for the electricity they do use, but do not earn the rebate (money back on bill) on that occasion. [12]

[11] CSIRO, Op cit p.12

[12] Ibid p.12

Tariff type	Features
Real-time Pricing	> Customer pays a particular price for each kWh of electricity used, and this price varies hour-by-hour so as to more closely reflect the true costs of supplying electricity at any one time. Ordinarily, the price is: > Higher when it costs more to supply the electricity a customer wants to use (e.g., when other customers are wanting to use lots of electricity at that moment, for example during peak periods), and > Lower when it costs less to supply the electricity a customer wants to use (e.g., when other customers are not wanting to use lots of electricity at that moment, for example during off-peak periods). > Customer can usually find out the hour-by-hour prices for the next day either by mobile alerts, logging on to a website, or calling a toll-free number. They may also have access to a web portal or enabling technology (e.g., in-home display) that shows the price at a particular time. > In some cases, the customer is notified the day before (e.g., by text message, email) if the prices are going to be especially high. [13]
Variable Peak Pricing	> A hybrid of Time of Use and Real-time pricing with defined periods for peak, shoulder and off-peak rates, but the price established for the peak period varies with market conditions.

Most of these tariff structures were included in the CSIRO Study which found consumers to be particularly resistant to the Real-time pricing option, with only capacity pricing (demand tariff) found to be less favourable. The CSIRO Study found that only with a compelling money-back guarantee would such a tariff be considered acceptable by consumers.[14]

The CSIRO study also found Critical Peak Pricing and Peak Time Rebates both had greater consumer appeal, though even with the addition of risk relief mechanisms, their acceptance was still significantly lower than a flat rate pricing structure.[15] Both these tariffs have broader, more predictable and manageable lower cost periods which only confront the consumer for a few hours on a few days each year.[16]

The CSIRO Study found that of all the cost-reflective options:

> *"Peak Time Rebates appear to predominate … perhaps because they feature potential gains rather than losses. ... In other words, the consumer stands only to gain (via rebates for reduced peak consumption), and never to lose (via higher charges for peak consumption). They are also offered the perceived certainty that comes with a flat rate tariff."*[17]

Variable Peak Pricing was not considered in the CSIRO study, but like all these tariff options, it would require customer education to ensure its effectiveness to actually change consumption behaviour.

All of these tariffs require an Interval meter as a minimum and preferably a Smart Meter coupled with an in-home device to manage appliance consumption. Given our existing metering technology and the results of the CSIRO Study, we are not proposing such tariffs in this TSS. However, these remain options we will reconsider, in conjunction with our customers and stakeholders, for the next TSS.

5.3.12 Meter upgrade costs

Overwhelmingly, the feedback we received indicated that customers should pay for any meter upgrades they undertake, but that the price should be able to be recouped over a longer period – say two to five years. We received just one response that thought networks should absorb the costs of Interval or Smart Meter upgrades given it would allow for more efficient use of the network.

Our standard meter installation is a Type 6 basic accumulation meter as this has the lowest cost to the customer – a one phase meter costs about $36 plus installation. Some feedback thought that Interval meters should be our

[13] Ibid p.13

[14] Ibid p.6

[15] Ibid p.6

[16] Ibid p.8

[17] Ibid p.8

default installation meter. Our meter price list does contain Interval meter prices as an option. Rather than force customers to pay for a more expensive meter, we will develop a customer brochure on the functionality and alignment of meter types to tariffs and add this to the Electricity Network Pricing section of our website.

It is expected that the proposed Competition in Metering Rule change, currently being considered by the AEMC, will also address this issue. At this stage, Meter Providers will begin the competitive rollout of meters in 2017 and are expected to provide customers with a range of meter payment and ownership options.

It was also suggested that Interval and Smart Meter costs should take the cost savings from moving to manual meter reading to remote reading into account. Our meter prices are cost-reflective and have been reviewed and approved by the AER. As such, remotely read meters have been priced to take into account the cost difference between manual and remote readings.

5.3.13 Public lighting charges

There were three issues raised in relation to Public Lighting:

> Concern was raised as to the delay in the implementation of a street lighting price structure for LED lighting in our network area.

> It was questioned whether we have any incentive to upgrade street lights to more efficient lighting.

> Concern was also raised around the need to recover the cost of capital for existing public lighting.

Where Councils decide that they want to upgrade their lighting to more efficient options with a proven technology, we facilitate this upgrade with a bulk luminaire replacement program at the customer's cost.

We are looking to introduce an LED luminaire tariff, however, we are unable to progress this with the AER until after the appeal process relating to our 2014-19 regulatory determination has been finalised. Once the appeal process has been completed we will endeavour to get an LED tariff rate in place as soon as possible and offer it as an option within our standard streetlight inventory.

The NSW Government is currently exploring barriers to the introduction of more efficient public lighting. Unrecovered capital is one of the matters being considered as part of this review.

5.3.14 Controlled Load tariffs

We offer Controlled Load tariffs for our low voltage customers whose consumption does not exceed 160 MWh per year. Controlled Load tariffs allow customers to move their use of certain appliances, for example an electric hot water system or in slab heating, to a cheaper tariff rate period, generally overnight or overnight with a daytime boost. Controlled Load energy supply is managed by the network and customers need a specific socket that is hard wired for this purpose.

It was suggested that Controlled Load tariffs should be more widely promoted and that there is scope to consider a third controlled rate tariff that operates at all other hours of the day except the evening peak. The current demand on our network would not make a third Controlled Load tariff viable at this stage. In terms of promoting Controlled Load tariffs, we will create a Controlled Load brochure and add this to the Electricity Network Pricing section of our website for customers to access.

This is a tariff we encourage customers to consider where they can move loads to off-peak hours. We see this tariff as an important option for our customers, especially as the take-up of electric vehicles continues.

5.3.15 Food & Fibre tariff

We asked for feedback on whether specific Food & Fibre tariffs should be developed for the NSW Agricultural industry. This is an area in which we received conflicting feedback from our customers and stakeholders.

Some irrigators / growers / industry groups thought:

> There should be multiple tariffs and flexible tariffs to fulfil the diverse electricity needs of their users;

> Network tariffs should not discourage irrigators / growers from participating in national and state water efficiency and land care programs;

> Network tariffs should not discourage irrigators / growers from utilising technologies and infrastructure that contributes to the national goal of increased food and fibre production;

> Network tariffs should allow for an efficient use of electricity consuming equipment on farm;

- Network tariffs should allow for an optimal water application that best assists plant growth;
- Capacity charges must be lower and more flexible;
- Weekend tariffs should be lower and have no associated demand charge;
- Alternative models for electricity pricing such as forward selling of 'electricity bundles' may offer a potential solution.

Other stakeholders believed that in developing cost reflective network tariffs there needs to be a balance between capturing the unique characteristics of certain customer classes and having such an expansive set of tariffs that it ultimately becomes administratively costly and burdensome.

There was also concern that in attempting to separately treat customers based on industry rather than usage, there was an increased risk of cross subsidisation. It was thought that there are other industries that face seasonal usage and occasional downturns, for example Aquatic centres.

> *"Network's should aim to achieve cost-reflective pricing across the network and not continue to provide price distortions. If this means raising charges at peak times then that is the outcome …"*[18]

These groups saw the industry issues as being the responsibility of Government, not networks, with policy changes and the provision of industry assistance providing better solutions.

As part of our consultation with industry groups we presented some indicative cost reflective Food & Fibre tariffs and asked for input on any alternative options we should consider. The feedback from these groups was for: flat rate tariffs, the removal of demand charges, more flexible demand charges, or the forward selling of 'electricity bundles' at a set rate that could be used at any time. Such tariffs would not send efficient price signals to customers, nor would they be compliant with the new Rules. As such, we have not implemented these requested changes or a separate set of tariffs for separate industry groups in this TSS.

5.3.16 Virtual net metering

As mentioned in section 4.3.4, Virtual Net Metering (VNM) is a developing market. Feedback on VNM was not specifically requested from our customers, but we received the following key points:

- Local generation could be used to provide Ancillary Services such as reactive power support or be islanded to provide micro-grids during major outages;
- Local network charges for the actual use of the network assets should be developed rather than billing full network charges;
- Customers would likely be willing to pay for the higher administrative costs that this pricing option creates as they would be supporting renewable energy sources and likely providing industry and employment in regional areas;
- It provides a win-win for the network and customers - the network provides local generators with access to bigger markets with a high level of reliability; allows local generators to run systems for maximum efficiency; and supports the technical requirements of consumers. In turn the local generators provide the networks with reduced transmission and distribution losses; the potential to save money on network investment; reduced emissions; increased resilience of the network and technical network services;
- Overall, it was also considered to be a viable and more socially equitable alternative to customers leaving the grid.

Essential Energy is currently undertaking a VNM trial in Byron Bay in conjunction with the Institute for Sustainable Futures. Some of the expected key outcomes of this trial are: a recommended methodology for calculating local network charges; a full assessment of the metering requirements and indicative costs for the introduction of local electricity trading; and the economic modelling of the benefits and impacts of local network charges and local electricity trading.

The results of this trial will be considered in developing our next TSS and we will continue to consult with our customers on the possibility of extending VNM across our network area.

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[18] Adam Clarke, *Response to NNSW Issues Paper*, October 2015

5.3.17 Period of time used to model LRMC

There was some criticism as to the time period (four years) over which we modelled the LRMC. Some feedback thought such a timeline would distort any cost-reflective signals as it is not a period of time over which all factors of production can be varied.

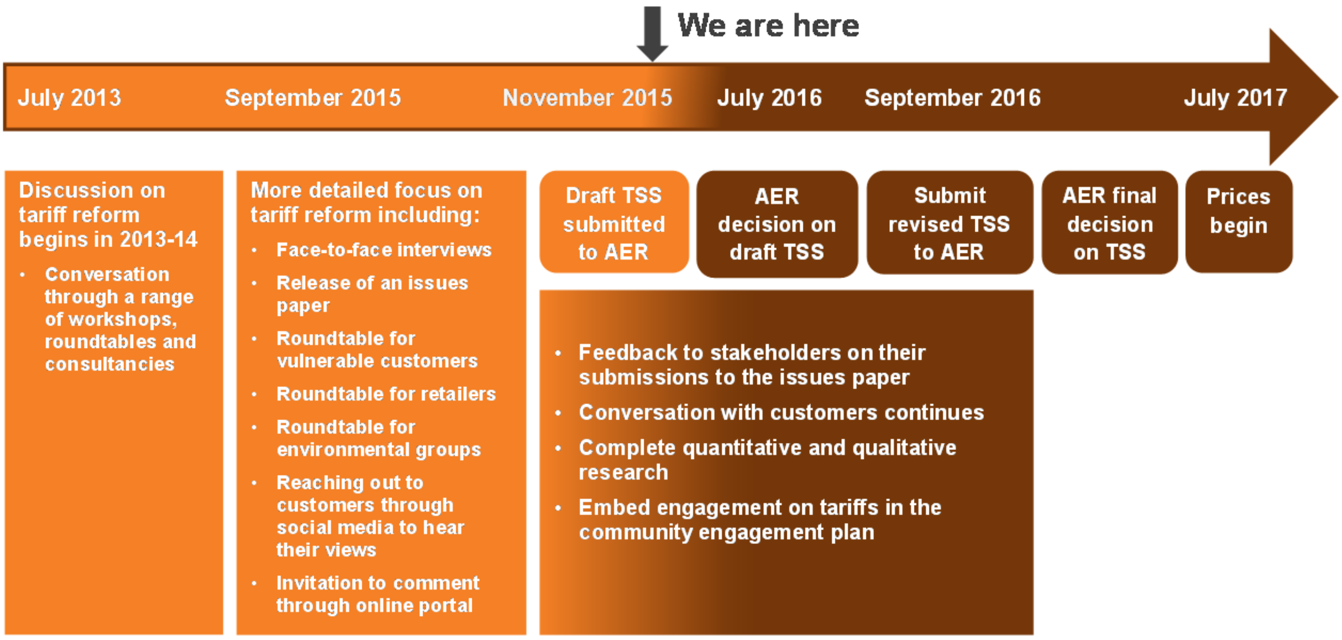
We aligned our LRMC period to our current regulatory period as this is the period over which our opex and capex expenditure levels have been approved by the AER. This has meant it is only a four year calculation for this TSS.

5.4 Future customer and stakeholder engagement

We appreciate that our consultation process in developing this TSS was compressed and did not allow sufficient time for us to gather the requested level of detail for certain topics of discussion. We would like to stress that we will continue our customer and stakeholder consultations in good faith between now and September next year when we submit our final TSS to the AER.

The timeline for finalising this TSS continues through to July 2017 (see Figure 5-4 below) when the associated prices will begin. We will undertake more formal customer and stakeholder engagement in 2016 in the lead up to our final TSS submission. In the meantime, we encourage customers and stakeholders to provide any comments on this TSS through to us or directly to the AER.

Figure 5-4: TSS development timeline



We will also undertake consultation and engagement as part of our subsequent regulatory submissions.

We don't intend to update our tariff structures often, and will only do so after consultation with our customers. The Rules allow us to seek amendments to an existing TSS only for events that occur beyond our reasonable control and that could not have reasonably been foreseen at the time of writing the TSS.

Our structures may change in future TSS periods to:

> Reflect customer preferences;

> Improve price signals to customers; or

> Encompass changes within the electricity market that impact on our costs.

6. OUR PROPOSED NETWORK TARIFF STRUCTURES

This section outlines the overall structure of our proposed network tariffs and how we aim to transition our customers to more efficient tariffs. Our proposed tariffs have been developed to meet the network pricing objective and principles set out in the Rules.

6.1 Assigning customers to tariffs

An overview of our policy and procedures for assigning and reassigning customers to tariffs can be found in section 3.5.6. The detailed policies and procedures can be found in Attachment 6 - *Policies and procedures for assignment and reassignment of tariffs* to this TSS.

6.2 Our proposed tariff classes

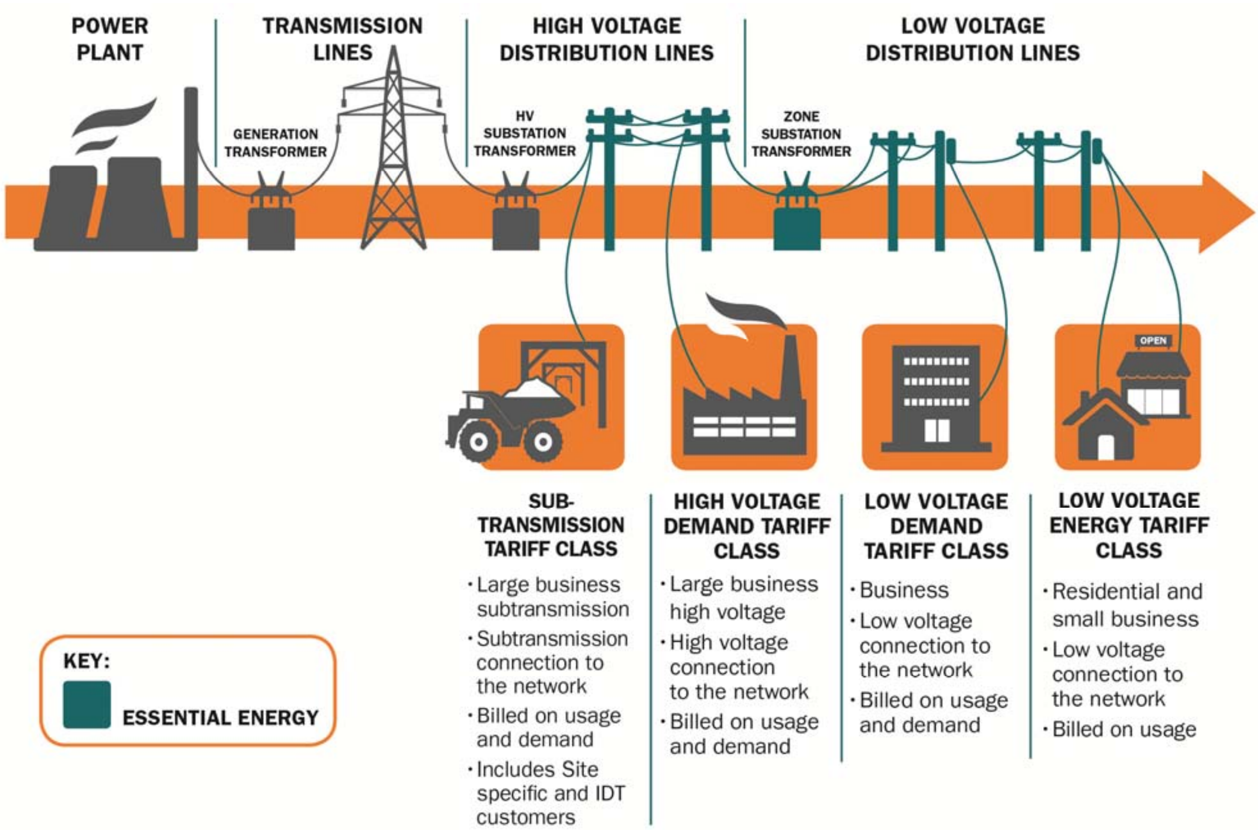
Our tariff classes have been established taking into consideration historical pricing structures; existing metering capability and the cost effectiveness of metering options; the connected voltage level; and the cost-benefit of providing further disaggregation into additional tariff classes.

We propose to group our customers into one of the following five tariff classes:

1. Subtransmission (including Inter Distributor Transfers)
2. High voltage demand
3. Low voltage demand
4. Low voltage energy
5. Unmetered

These classes are identical to our existing tariff classes apart from the current Inter Distributor Transfer (IDT) class which will now be included in the Subtransmission tariff class. A summary of our tariff classes, customer types and their associated characteristics is shown in Figure 6-1 below.

Figure 6-1: Proposed tariff classes, customer classes and their associated characteristics



There is one tariff class not shown in Figure 6-1 above - Unmetered customers. Unmetered customers do not have a meter, and are therefore not billed based on a meter reading. An example is street lighting.

Apart from our large customers who are on site specific tariffs, all other customers have network prices that are averaged for their customer class.

Alternative Control Services cannot be slotted into tariff classes for retail customers as such, but are grouped by the type of service provided. The three types of Alternative Control Services we provide are public lighting (for councils), metering charges for Type 5 and 6 meters and ancillary network services. These are described in more detail in section 3.4 and the prices for these services are included in Attachment 7.

6.3 Our proposed tariff structures

Our proposed tariff structures for 2017-19 are identical to our current structures. This reflects our desire to better understand how the specific design of newer and more innovative alternative tariff structures (for example demand-based tariffs) might affect consumer behaviour. Given such tariffs are currently untried for residential customers we want to better understand how they might impact network usage and capacity constraints within our network, This will be informed by the outcomes resulting from the introduction of demand-based charges by the Victorian distributors from 2017. Given the nature and size of our network (that is a rural radial network) we believe that caution is required in introducing new tariff structures to ensure that appropriate price signals are provided without creating unexpected impacts on customer bills.

An inappropriately formulated demand tariff creates the risk of inefficient investment in Interval metering technology by our customers, in response to the incentives that might be created by the new tariff structure. It follows that the overwhelming presence of basic accumulation meters within our network area suggests that a poorly designed demand tariff creates the prospect of lessening efficient use of the network (through the inefficient adoption of Interval meters) and so might be counterproductive to the distribution pricing objectives set out in the Rules.

As discussed throughout section 5.3, the CSIRO Study (Attachment 10) found demand charges to be the least preferred customer tariff option and this supports our current position.

Our proposal to maintain our current tariff structures and undertake a more considered investigation of innovative tariff structures as part of the development of the next TSS is consistent with the principles set out in the Rules. Our approach promotes more efficient use of the network via the tariff levels chosen within the prevailing tariff structures, as we have sought to base our tariffs on the long-run marginal cost within our network, while balancing the bill impact on our customers.

The eligibility requirements, tariff structures and tariff components for each customer type are outlined in the following sections.

6.3.1 Residential customers network tariffs and charging parameters

We propose to continue offering two residential tariffs under the “Low voltage energy” tariff class. These tariffs and the associated eligibility criteria are shown in Table 6-1 below:

Table 6-1: Eligibility for Residential customer tariffs

Tariff	Eligibility
Residential declining block	> Low voltage connection > Premises wholly used as a private dwelling where consumption does not exceed 160 MWh per year > Default network tariff for most residential customers
Residential Time of Use	> Low voltage connection > Premises wholly used as a private dwelling where consumption does not exceed 160 MWh per year > Time of Use capable meter > Optional tariff

The associated tariff structures and charging parameters for residential customers are shown in Table 6-2 below. The structures are identical to our existing tariffs for residential customers.

Table 6-2: Residential network tariff structures and charging parameters

Tariff	Tariff structure	Measure	Charging parameter
Residential declining block	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Three tier declining block tariff > Step 1 applies to the first 1,000kWh per 91 days > Step 2 applies to consumption >1,000kWh and ≤1,750kWh per 91 days > Step 3 applies to all consumption >1,750kWh per 91 days
Residential Time of Use	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times

6.3.2 Small Business customers network tariffs and charging parameters

We propose to continue offering two tariffs to Small Business customers under the “Low voltage energy” tariff class. These tariffs and the associated eligibility criteria are shown in Table 6-3 below:

Table 6-3: Eligibility for Small Business customer tariffs

Tariff	Eligibility
Business declining block	> Low voltage connection > Business premises where consumption does not exceed 160 MWh per year > Default network tariff for most small business customers
Business Time of Use	> Low voltage connection > Business premises where consumption does not exceed 160 MWh per year > Time of Use capable meter > Optional tariff

The associated tariff structures and charging parameters for our Small Business customer tariffs are shown in Table 6-4 below. The structures are identical to our existing tariffs for Small Business customers.

Table 6-4: Small Business customers proposed network tariff structures and charging parameters

Tariff	Tariff structure	Measure	Charging parameter
Business declining block	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Two tier declining block tariff > Step 1 applies to the first 5,000kWh per 91 days > Step 2 applies to consumption >5,000kWh per 91 days
Business Time of Use	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times

6.3.3 Controlled Load customers network tariffs and charging parameters

We propose to continue offering two tariffs to Controlled Load customers under the “Low voltage energy” tariff class. These tariffs and the associated eligibility criteria are shown in Table 6-5 below:

Table 6-5: Eligibility for Controlled Load customer tariffs

Tariff	Eligibility
Controlled load 1	> Low voltage connection > Premises where consumption does not exceed 160 MWh per year > Premise has another primary metering point present at the same metering point as the secondary load and the load is remotely controlled > Load is permanently connected or on a dedicated power circuit with indicators to show when supply is available. > This tariff is not available for the top boost element of a two element water heater for new connections.
Controlled load 2	> Low voltage connection > Premises where consumption does not exceed 1I made these ones a few days ago, 60 MWh per year > Premise has another primary metering point present at the same metering point as the secondary load and the load is remotely controlled > Load is permanently connected or on a dedicated power circuit with indicators to show when supply is available.

The associated tariff structures and charging parameters for our Controlled Load customer tariffs are shown in Table 6-6 below. The structures are identical to our existing tariffs for Controlled Load customers.

Table 6-6: Controlled Load customers proposed network tariff structures and charging parameters

Tariff	Tariff structure	Measure	Charging parameter
Controlled load 1	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Flat rate based on usage between five to nine hours overnight on weekdays and extra hours on weekends except where the load is controlled by a time clock
Controlled load 2	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Flat rate based on usage between 10 to 18 hours per day on weekdays and all hours on weekends except where the load is controlled by a time clock

6.3.4 Business customers network tariffs and charging parameters

We propose to offer three network tariffs for Business customers under the “Low voltage demand” tariff class. The tariffs and the associated eligibility criteria are shown in Table 6-7 below.

Table 6-7: Eligibility for Business customer tariffs

Tariff	Eligibility
Low voltage – Time of Use average daily demand	> Low voltage connection > Business premises where consumption exceeds 160 MWh per year > Monthly load factor greater than 60% for at least four of the most recent 12 months coinciding with a minimum on season anytime monthly demand of 1500 kVA. > Intended for customers with a seasonal demand > Interval capable meter
Low voltage – Time of Use three rate demand	> Low voltage connection > Business premises where consumption exceeds 160 MWh per year > Interval capable meter
Low voltage – Time of Use demand alternative	

The associated tariff structures and charging parameters for our Business customer tariffs are shown in Table 6-8 below. The structures are identical to our existing tariffs for Business customers.

Table 6-8: Business customers proposed network tariff structures and charging parameters

Tariff	Tariff structure	Measure	Charging parameter
Low voltage – Time of Use average daily demand	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times
	Demand	$/kVA	Demand charge calculated on the average daily time of use demand for peak, shoulder and off-peak periods for the month.
Low voltage – Time of Use three rate demand	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times
	Demand	$/kVA	Maximum demand charge based on the highest measured half-hour kVA demand registered in each of the peak, shoulder and off-peak periods during the month.
Low voltage – Time of Use demand alternative	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times
	Demand	$/kVA	Maximum demand charge based on the highest measured half-hour kVA demand registered in either the peak or shoulder periods during the month.

6.3.5 Large Business customers network tariffs and charging parameters

We propose to continue offering two network tariffs for Large Business customers under the "High voltage demand" tariff class. The tariffs and the associated eligibility criteria are shown in Table 6-9 below:

Table 6-9: Eligibility for Large Business customer tariffs

Tariff	Eligibility
High voltage – Time of Use average daily demand	> High voltage connection and metering point > Business premises where consumption exceeds 160 MWh per year > Interval capable meter
High voltage – Time of Use monthly demand	> High voltage connection and metering point > Business premises where consumption exceeds 160 MWh per year > Monthly load factors >60% for at least four of the most recent 12 months coinciding with a minimum on season anytime monthly demand of 1500 kVA. The minimum demand and load factor requirements will be waived where a generator supports a substantial part of the load on the load side of the meter. > Intended for customers with a seasonal demand > Interval capable meter

The associated tariff structures and charging parameters for Large Business customer tariffs are shown in Table 6-10 below. The structures are identical to our existing tariffs for Large Business customers.

Table 6-10: Large Business customers proposed network tariff structures

Tariff	Tariff structure	Measure	Charging parameter
High voltage – Time of Use average daily demand	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times
	Demand	$/kVA	Demand charge calculated on the average daily time of use demand for peak, shoulder and off-peak periods for the month.
High voltage – Time of Use monthly demand	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times
	Demand	$/kVA	Maximum demand charge based on the highest measured half-hour kVA demand registered in each of the peak, shoulder and off-peak periods during the month.

6.3.6 Large Business Subtransmission customers network tariffs and charging parameters

We propose to continue offering two network tariff options for Large Business Subtransmission customers under the “Subtransmission” tariff class. The tariff and the associated eligibility criteria are shown in Table 6-11 below:

Table 6-11: Eligibility for Large Business Subtransmission customer tariffs

Tariff	Eligibility
Subtransmission – three rate demand	> Subtransmission connection (as defined by Essential Energy) > Business premises where consumption exceeds 160 MWh per year > Interval capable meter > Not applicable for connection to dual purpose subtransmission/distribution circuits
Site specific	> Certain large business customers > On a case-by-case basis by application to Essential Energy

The associated tariff structure and charging parameters for our Large Business Subtransmission customer tariffs is shown in Table 6-12 below. The structures are identical to our existing tariffs for Large Business Subtransmission and Inter distributor transfer customers.

Table 6-12: Large Business Subtransmission customers proposed network tariff structures

Tariff	Tariff structure	Measure	Charging parameter
Subtransmission – three rate demand	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times
	Demand	$/kVA	Maximum demand charge based on the highest measured half-hour kVA demand registered in each of the peak, shoulder and off-peak periods during the month.
Site specific	Various	Various	Various combinations of fully cost reflective structures

6.3.7 Unmetered customers network tariffs and charging parameters

We propose to continue offering two network tariff options for Unmetered customers under the “Unmetered” tariff class. The tariff and the associated eligibility criteria are shown in Table 6-13 below:

Table 6-13: Eligibility for Unmetered customer tariffs

Tariff	Eligibility
LV Unmetered NUOS	> Type 7 meter > Applies to loads agreed between a Minister and AEMO > All new unmetered supply connections will have this tariff applied
LV Public Street lighting TOU NUOS	> Type 7 meter > Applies to loads agreed between a Minister and AEMO > All new public street lighting connections will have this tariff applied

The associated tariff structure and charging parameters for our Unmetered customer tariffs is shown in Table 6-14 below. The structures are identical to our existing tariffs for Unmetered customers.

Table 6-14: Unmetered customers proposed network tariff structures

Tariff	Tariff structure	Measure	Charging parameter
LV Unmetered NUOS	Fixed	$/day	Network access charge reflecting a fixed amount per day
	Energy	c/kWh	Flat rate based on usage
LV Public Street lighting TOU NUOS	Energy	c/kWh	Peak, shoulder and off-peak rate based on energy consumed in each period > Peak period is from 7am to 9am and 5pm to 8pm on weekdays > Shoulder period is from 9am to 5pm and 8pm to 10pm on weekdays > Off peak period is at all other times

6.4 What does efficient pricing look like?

The objective of the new Rule is that the network prices we charge each customer should reflect our business's efficient costs of providing network services to that customer. Specifically, each tariff must be based on the long run marginal cost (LRMC) of providing the service to which it relates to the retail customers assigned to that tariff.

Efficient pricing preserves the LRMC (cost of consuming or adding one more unit) while also allocating costs that have already been incurred (residual costs) in a way that will provide price stability and take into consideration any impact to customers.

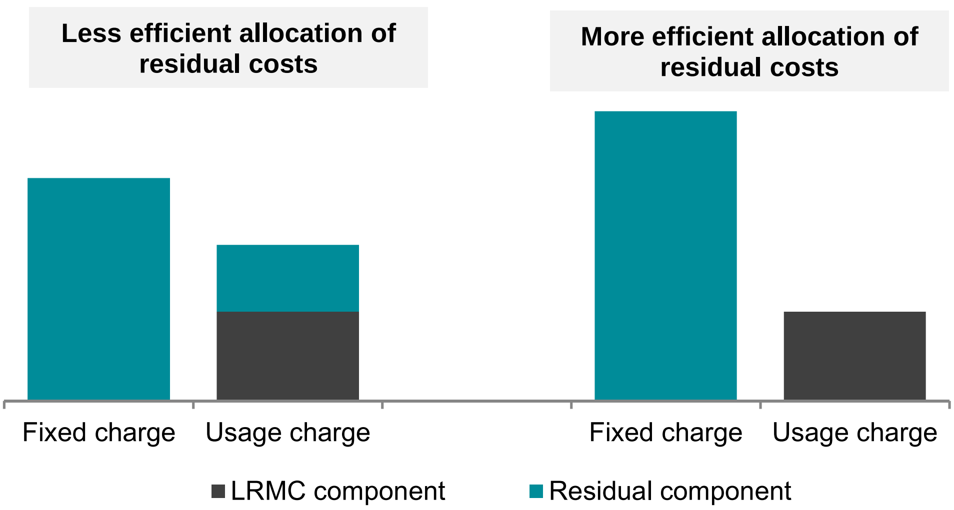
Efficient pricing needs to signal to customers the future network cost of consuming the next unit of electricity. Where there are no network constraints, such as in off-peak times, this cost will be very low. However, if the network is reaching capacity at peak times, the cost to the network of consumers using more energy/demand at that time will grow until it requires us to augment the network to continue to meet the demand. These additional costs should, under the Rules, be reflected in the variable usage charge of the tariff structure.

To encourage customers to make more efficient use of the network (make better use of the spare capacity currently available), more efficient price structures would have:

- A larger fixed component, to better reflect the costs of building and maintaining the current network
- Lower variable charges (reflecting the cost of future increases to the network from additional consumption.)

We have tried to show the difference between inefficient and efficient network pricing in Figure 6-2 below:

Figure 6-2: Inefficient vs efficient allocation of residual costs



6.5 Strategy for transitioning customers from non-cost reflective network tariffs to cost reflective tariffs

In 2013-14, Essential Energy began discussions with customers about moving from our historic flat rate usage tariffs to declining block tariff structures. Declining block tariffs were implemented and approved by the AER in our 2014-15 Pricing Proposal for two of our most common residential and small business tariffs, albeit with each block applied at the same price. In 2015-16, these block prices were varied to rates that now decrease as consumption increases. The varied structure will allow greater flexibility in ensuring distribution tariffs move towards cost reflectivity and will also help reduce bill shock for many of our customers.

The declining block tariff was introduced to provide Essential with greater flexibility to manage the bill impact of transitioning from our flat rate usage tariff to more efficient tariffs over time. At the time, the usage charge of our flat rate tariff was far in excess of our estimates of the LRMC. In simple terms the declining block tariff structure:

- Allows us to segment customers into three usage categories (two for small business customers), with the marginal charge, that is the higher block charge, being closer to the LRMC for those customers that are high consuming customers, thereby providing an improved price signal for using additional energy;
- Manages bill impacts by providing greater revenue stability - treating the lower blocks like a fixed charge and not discouraging consumption under revenue cap regulation; and
- Does not require customers to invest in new metering technology.

At this stage we are proposing only modest increases to the fixed component of our tariffs, limited to the average increase for all tariffs in a class for any one year. For declining block tariffs we will also increase the differential in the rates between the blocks, with the first block increasing by more than the subsequent blocks and the third block moving towards LRMC. We see this as an efficient transition path to reflecting LRMC in the variable component of these tariffs.

The tariffs (and tariff structures) proposed in this TSS more accurately reflect the forward looking costs our customers impose on the network. Although some variable components of our tariffs (energy and/or demand) are not covering the LRMC we will transition them up to LRMC levels over a period of time to limit the immediate impact on customers. As such, we believe they are delivering efficient price signals to customers and, as explained by Houston-Kemp in their report at Attachment 4, they are compliant with the Rules. The DBT for residential and small business customers will also shield customers from large swings in prices by achieving revenue stability.

Feedback indicated a timeline transition preference of three to five years (section 5.3.2), however we will take a longer period to transition to efficient pricing levels.

We will also introduce different rates for shoulder energy and demand that are lower than peak rates, to better reflect our costs of supplying customers during those time periods.

6.6 Future tariff structures and pricing directions

We will update our tariff structures as part of our regulatory proposals. We can also seek amendments to an existing TSS for events that occur beyond our reasonable control and that could not have reasonably been foreseen at the time of writing the TSS.

In accordance with the Rules, we will only make changes to our TSS after consulting with our customers and stakeholders. This will ensure our changes are supported and easily understood. In Section 7 we outline the approach we will take to calculating future tariff structures using LRMC.

6.7 Alternative Control Services

As discussed in section 3.4, our Alternative Control Services (Type 5 and 6 metering, public lighting and ancillary network services) are incurred by individual customers.

Our approach to determining Alternative Control Service charges was detailed in our regulatory proposal for the 2014–19 regulatory control period and our AER approved prices for these services for the 2017–19 TSS period are set out in the indicative pricing schedule at Attachment 7 to this TSS.

7. OUR TARIFF SETTING METHODOLOGY

Our tariffs have been developed in accordance with the distribution pricing principles set out in the Rules. This section sets out the approach we have adopted in setting our proposed tariffs, and explains how we have complied with the Rule requirements.

7.1 The network pricing objective and pricing principles

Clause 6.18.5(f) of the National Electricity Rules states that:

> The *network pricing objective* is that the tariffs that a *Distribution Network Service Provider* charges in respect of its provision of direct control services to a *retail customer* should reflect the *Distribution Network Service Provider's* efficient costs of providing those services to the *retail customer*.

This objective seeks to ensure that network tariffs recover the efficient costs of providing distribution network services to customers. To achieve this objective, the Rules set out a number of pricing principles, which we must comply with when setting our tariffs.

Specifically, the pricing principles require that:

- Revenue expected to be recovered for each tariff class lies between an upper bound being stand alone cost, and a lower bound being avoidable cost – Rule 6.18.5(e);
- Each tariff must be based on the *long run marginal cost* of providing the service - Rule 6.18.5(f);
- Revenue expected to be recovered from the tariff reflects the efficient cost of providing services to customers on that tariff, allows total revenue to be recovered, and does so in a manner that minimises distortions to the price signal for efficient use of the network – Rule 6.18.5(g);
- In setting tariffs, distributors consider the impact on retail customers of changes in tariffs from the previous regulatory year – Rule 6.18.5(h);
- Tariffs be reasonably capable of being understood by customers – Rule 6.18.5(i); and
- Tariffs must comply with all applicable regulatory instruments – Rule 6.18.5(j).

The concept of marginal cost and more specifically LRMC is explored further in the following sections of this chapter.

Additionally, in structuring tariffs, Essential Energy will always aim to:

- Ensure our tariffs are simple and transparent;
- Fairly allocate costs between customers based on their share of relevant network costs;
- Maintain predictable and relatively stable prices over time;
- Empower customers to make efficient electricity consumption choices; and
- Alleviate or defer unnecessary capital expenditure that would otherwise increase prices to customers.

These goals reflect the requirements of the NEL and the Rules and reflect our understanding of what customers want from their electricity distributor.

7.2 Revenue from each tariff class lies between stand alone and avoidable cost

7.2.1 Methodology for estimating stand alone and avoidable cost

We have used current expenditure as the basis of the estimates of stand alone and avoidable cost. For example, to assess stand alone costs for the high voltage tariff class, we have identified the existing assets and operating expenditure that would be necessary to provide services to high voltage customers.

Our approach classifies each of the network's cost categories on the basis of two dimensions, that is:

Whether costs are direct or indirect – the framework assumes that a cost category is either:

- 'Direct', that is the cost can be attributed to a specific group of users and would not be incurred but for those users; or

- ‘Indirect’, that is the cost is common to multiple groups of users.

As an example, customer metering is directly attributable to individual customers. In contrast, operational expenditure costs are generally indirect, for example the cost of equity raising cannot be attributed to specific customers or customer groups.

Whether costs are scalable or non-scalable – the framework assumes that a cost category is either:

- ‘Scalable’, that is the cost tends to increase in proportion to the scale at which the service is provided; or
- ‘Non-scalable’, that is the cost is independent of the scale at which the service is provided.

For example, maintenance and repair costs are considered scalable as they are likely to be highly dependent on the physical size of the network. In contrast, equity raising costs are likely to be relatively independent of network characteristics such as the number of customers or maximum demand.

We have then calculated avoidable and stand alone costs as follows:

- **Avoidable cost** for each tariff class is the sum of all direct costs multiplied by a weighting, which represents the proportion of direct costs that are attributable to that tariff class.
- **Stand alone cost** for each tariff class is the sum of avoidable costs, non-scalable indirect costs and scalable indirect costs multiplied by a set of scaling factors that vary according to the particular costs in question.

For a more thorough and detailed explanation of the approach we have adopted, please refer to Attachment 4 - *Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles from Houston-Kemp* of this TSS.

7.2.2 Comparison of revenue and pricing bounds

Table 7-1 sets out our comparison of revenue as compared with our estimates of stand alone and avoidable cost for each tariff class.

Table 7-1: Proposed 2015-16 revenue ($M) by tariff class complies with the Rule

Tariff class	Avoidable	Stand alone	Proposed	Proposed revenue lies between stand alone and avoidable cost?
Low Voltage Energy	104	872	617	Yes
Low Voltage Demand	13	780	166	Yes
High Voltage Demand	4	503	39	Yes
Subtransmission	11	88	12	Yes
Inter distributor transfers*	0	38	0.5	Yes
Unmetered	0	384	4	Yes

* Although IDTs will form part of the Subtransmission tariff class, they are separated here to show that they currently comply with the Rules.

The results demonstrate that our proposed tariffs satisfy the pricing bounds as required by the Rules.

7.3 Our tariffs have been based on long run marginal cost, with residual costs recovered in a manner to minimise distortions in price signals

7.3.1 The concept of long run marginal cost

The long run marginal cost for an electricity network service requires consideration of the service that is being provided, so that the cost of incremental changes to that service can be estimated.

Our approach has involved defining the fundamental service that we provide to customers as an energised connection with a set of accompanying rights, which may include the right to:

- Withdraw up to a specified amount of power from a defined connection point at any time;
- Inject up to a specified amount of power into a defined connection at any time;

- Exercise the rights accompanying the energised connection with some expectation of reliability.

Each right gives rise to an obligation on the network – for example a right to withdraw creates an obligation on the network to invest in sufficient capacity, so as to provide that service to the customer. Sometimes these obligations are onerous and costly to fulfil, sometimes they are superfluous and result in no incremental cost.

Our definition of the fundamental service provided by an electricity network establishes a clear concept – a network provides an *energised connection service*. To estimate marginal costs we need to determine the way in which increased provision of this service translates into increases in forward-looking network costs.

The principal determinant of costs for our electricity network is the number and condition of our assets, combined with the large network area in which we operate – representing about 70 per cent of our costs. Our expected maximum (or 'peak demand') demand is the second most important cost driver. When peak demand increases, we must augment our network or risk the prospect of not being able to supply our customers. Our least influential cost driver is the number of customers connected to our network. It follows that the marginal cost of a new connection is principally how it impacts on our network capacity through its contribution to our localised system peak demand.

Our network's most important *obligation* arises from customers' right to withdraw power during the system peak. The marginal cost of an energised connection is, therefore, typically expressed in terms of the cost per kW (or cost per kVA) of maximum demand. Put another way, the 'cost of the next unit' is assumed to be the cost of supplying one more unit of demand during the peak demand.

We emphasise that the marginal cost of a network service depends on the characteristics of that service – that is, on the rights that accompany the energised connection. For example, the marginal cost may be influenced by the:

- Ability for the network to interrupt the customer's load (for example, Controlled Load)
- Part of the network to which the customer connects (for example, low voltage or high voltage).

It is therefore misleading to refer to *the* marginal cost of network services – the characterisation implies that there is a unique value. In the extreme, we could define a distinct service at every point in time, and for each voltage level, and geographic part of the network.

The economic principle of efficient pricing would then suggest that a different price should be charged for each of these services. However, such granular pricing is impractical and so, in practice, network businesses use tariff classes or similar concepts to aggregate customers to whom they provide similar services. Our proposed tariff classes are outlined in section 6.2.

7.3.2 Our estimates of long run marginal cost

There are a number of approaches that can be used to estimate the LRMC across our network. Having considered the inputs required and the practical application of each approach we have concluded that the average incremental cost method is the most suitable for Essential Energy. Our approach is consistent with what has been adopted by most distributors in Australia.

Further detail on applying the average incremental cost methodology for Essential Energy, estimation of stand alone and avoidable costs and allocation of residual costs is set out in Attachment 4 - *Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles from Houston-Kemp*.

7.3.3 Recovery of residual costs and customer impacts

Setting our charges based on the long run marginal cost would result in us not recovering all of our required revenue. The Rules require us to consider how best to recover these remaining costs – sometimes referred to as residual costs – in a manner that minimises distortions to price signals (therefore minimises the extent to which it varies from the LRMC), while taking into account the bill impact on customers.

For the purposes of this TSS our approach has focused on the bill impact to our customers, while improving price signals for efficient use of the network where feasible. Practically, we have sought to limit increases in the fixed component of our tariffs in line with average changes in prices, while recovering the remainder of our maximum allowable revenue from customers in a manner that minimises distortions in price signals. To achieve this we have sought to recover more of our residual costs from those usage tariffs that appear less responsive to changes in price (for example the lower blocks of our proposed declining block tariffs).

Table 7-2 below indicates our LRMC estimates by voltage level, as well as our aggregated LRMC estimate. Aggregated LRMC means it includes the LRMC from the lower voltages, so that low voltage (LV) includes the LRMC of both high voltage and Subtransmission.

Table 7-2: LRMC estimates

Voltage level	LRMC Estimate ($/kVA pa)	Aggregated LRMC ($/kVA pa)
Low Voltage	150.49	315.75
High Voltage	132.79	165.26
Subtransmission	32.47	32.47

Table 7-3 sets out how our proposed tariffs for the 2018/19 year compare with our estimate of the LRMC. The LRMC has been translated to the specific tariff component for comparison, however our proposed tariff components for demand based tariffs still have energy charges as well as demand charges. These need to be considered together when comparing to the LRMC.

Table 7-3: LRMC comparison to proposed tariff components

Block tariffs

Code	Name	LRMC	Proposed 18/19 DUOS			
		Charge c/kWh	NAC $/year	Block 1 Energy c/kWh	Block 2 Energy c/kWh	Block 3 Energy c/kWh
BLNN2AU	LV Residential DBT	4.23	332.13	7.852	7.349	6.859
BLNN1AU	LV General supply DBT	4.23	332.13	12.991	9.600	n/a

TOU tariffs

Code	Name	LRMC			Proposed 18/19 DUOS			
		Peak c/kWh	Shoulder c/kWh	Off-peak c/kWh	NAC $/year	Peak c/kWh	Shoulder c/kWh	Off-peak c/kWh
BLNT3AU	LV Residential TOU	14.68	7.34	0.00	322.29	9.554	8.992	2.997
BLNT2AU	LV TOU <100MWh	14.68	7.34	0.00	2,647.61	9.554	8.992	3.800

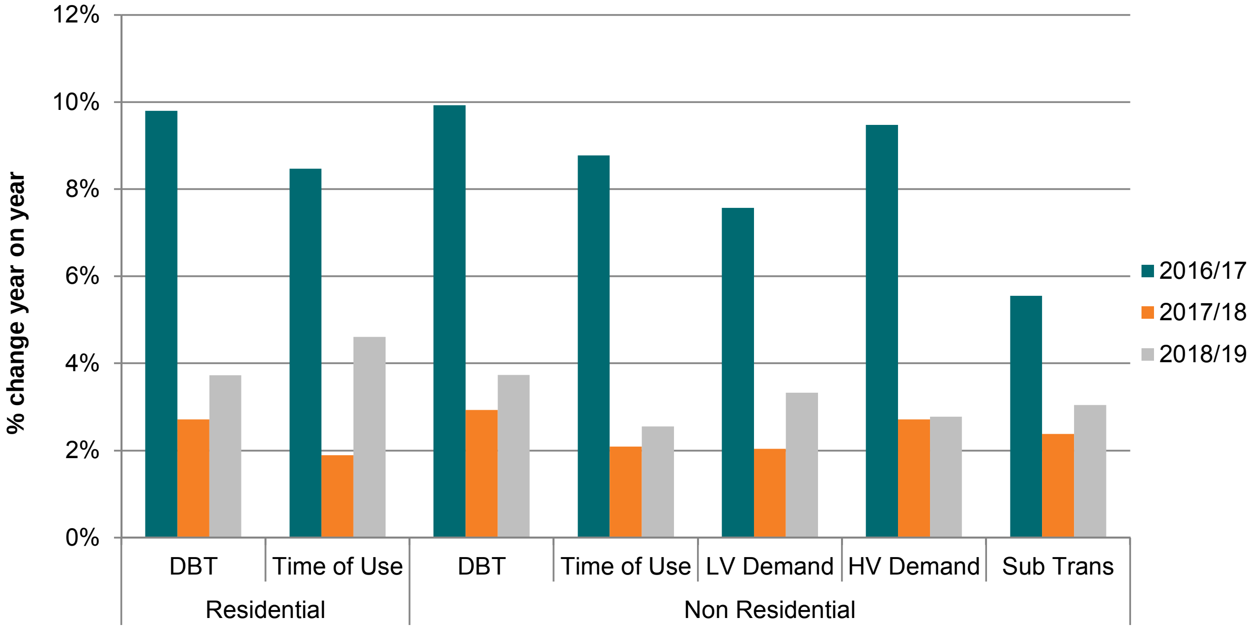
Demand tariffs

Code	Name	LRMC			Proposed 18/19 DUOS						
		Demand charge $/kVA/M			NAC $/year	Energy charge c/kWh			Demand charge $/kVA/M		
		Peak	Shoulder	Off Peak		Peak	Shoulder	Off-peak	Peak	Shoulder	Off Peak
BLND3AO	LV TOU Demand 3 Rate	13.16	13.16	0.00	6,311.08	0.736	0.692	0.184	10.079	9.486	2.304
BHND3AO	HV TOU mthly Demand	6.89	6.89	0.00	7,977.04	0.580	0.546	0.284	8.966	8.439	2.549
BSSD3AO	Sub Trans 3 rate Demand	1.35	1.35	0.00	7,941.98	0.218	0.126	0.103	3.503	2.497	0.995

Importantly, we have considered the bill impact of these tariffs so as to ensure that our tariff changes strike an appropriate balance between improving the price signal for efficient use of the network while taking into account the bill implications for customers. Indeed, our proposed declining block tariff provides us with significant flexibility through the choice of the block charges, to manage bill impacts whilst seeking to more closely align tariffs to the LRMC, at least for some of our customers.

Figure 7-1 below sets out our analysis of bill impacts for customers on our main tariffs for the remainder of this regulatory period.

Figure 7-1: Customer bill impacts by tariff type (year on year change)



The customer impact above is based on the actual average annual MWh for the different customer groups:

- Residential DBT and TOU customers consuming 5MWh per annum;
- Non Residential DBT and TOU 1consuming 8MWh per annum;
- LV Demand customers consuming 496MWh per annum;
- HV Demand customers consuming 5.7GWh per annum;
- Subtransmission customers consuming 13.2GWh per annum.

The graph shows the percentage increase in the NUOS bill from one year to the next. Importantly, using other methods of transitioning our DBTs and other tariff structures, to more closely align with our estimates of LRMC, may have led to higher increases in bills for the average customer, particularly in 2016/17.

In summary, we believe that our proposed tariffs provide improved price signals for efficient use of the network, while balancing the bill impact of the proposed changes for customers, consistent with the distribution pricing principles.

7.4 Our tariffs are easily understood by our customers

Much of our focus for this TSS has been to build our capabilities to analyse LRMC, and consider how price signals might impact customer use of our network and potentially avoid future network costs. Our customer engagement highlighted that our current tariff structures were well understood, and so these have been retained for this TSS – see section 6.3.

Importantly, part of the reason we have not introduced new, more innovative tariff structures at this time is our concern that these structures might not be easily understood by our customers - this would a direct contravention to the pricing principles. Should such structures be considered appropriate in the future, we believe it will be important to educate our customers to build the awareness necessary to satisfy this Rule requirement.

7.5 Treatment of pass through costs

7.5.1 Pass through of transmission costs

The AER allows Essential Energy to recover the transmission-related costs it pays. Transmission charges are a significant cost component for Essential Energy and are recovered as part of the total network charges levied on our customers.

Transmission related payments are known as TUOS charges and include:

- The cost of transmission related costs for use of transmission networks owned by TransGrid, Ausgrid and Powerlink;
- Avoided TUOS payments to embedded generators calculated in accordance with the Rules; and
- Payments for network services to other distributors for inter-distributor transfers.

Transmission charges are not in a form that readily translates into network price structures. Essential Energy translates historical energy and kilowatt demand charges from transmission authorities into equivalent peak, shoulder and off-peak energy rates in order to allocate those charges to the network services tariffs for most customers.

Essential Energy allocates transmission charges to network prices using the following principles:

- The total TUOS allocated to network prices aligns with total expected transmission related payments to be made by Essential Energy
- The pass through of transmission charges and the structure of network prices have been aligned wherever possible by Essential Energy
- Site specific customers have transmission charges allocated in a way that preserves the location and time signals of transmission pricing as per Section 6 of the Rules. These charges are passed through as closely as possible to reflect the manner in which the charges are levied on Essential Energy
- Network prices for all other customer classes (standard customers) have transmission charges allocated on an average basis due to the difficulties associated with equitably allocating the general and common service fixed charge as a fixed network access charge, and passing through location price signals which cannot be preserved when the end price is applied to many customers within the network.

For large customers with individual prices, the individual cost of transmission is directly assigned to the customer. The balance is allocated to standard customer classes.

Direct mapping to network prices for standard customer classes has not been possible due to the large fixed transmission charges that cannot be directly included in network price structures for these customers, which typically have a small fixed charge. More importantly, the customer's metering generally does not readily permit it as a lot of transmission charges are levied as demand kW charges. Due to these limitations, it is not possible to pass the same transmission cost drivers through to all customers in the same format as they are provided to Essential Energy.

While allocation of the large fixed charge component is reasonably discretionary, it has been apportioned between customer classes on the basis of their consumption. Allocation to customers in this way is a balance between equity and efficiency. Only the peak and shoulder energy component can be readily passed on to customers through distribution prices.

The transmission charges are allocated on their non-time of use energy, peak and shoulder energy consumption, and/or demand are added to the distribution network costs for each customer class. The intention of this mapping methodology is to preserve within the customer's price, to the extent possible, the cost drivers inherent in the transmission charge.

- Non-TOU price – the total transmission charge allocation for the class is divided by the total class consumption and added to the energy rate for the price. Average transmission charges would apply to smaller customers
- TOU price – the transmission allocation relating to the transmission demand and energy components is divided by the peak, shoulder and off peak consumption and added to the peak, shoulder and off peak energy rates. The transmission allocation relating to the fixed transmission component is added to the

TOU energy rates Demand TOU price – the transmission allocation relating to the transmission demand and energy components is divided by the peak, shoulder and off peak consumption and added to the peak, shoulder and off peak energy rates. The transmission allocation relating to the fixed transmission component is added to the TOU energy rates.

The fixed component of the transmission charge was originally largely determined from an 'anytime' energy allocation of costs. This component is apportioned between individual customers and customer classes on the basis of their anytime energy consumption. Allocation to customers in this way is a balance between equity and efficiency. The allocation of the transmission demand charge using peak and shoulder energy is justified on the basis that in the long run, the augmentation of the transmission network - and hence future costs - is related to peak and shoulder utilisation of the network.

7.5.2 Pass through of jurisdictional scheme costs

Is setting its tariffs, Essential Energy takes into account jurisdictional scheme amounts for approved jurisdictional schemes and ensures that these costs are passed on to customers. Additional requirements such as only 25 per cent of the NSW Climate Change Fund being recovered from residential customers is also adhered to. Adjustments are made for any under or over recoveries made in the previous year.

7.6 Summary of compliance with the distribution pricing objective and principles

We have adhered to the pricing objective and principles set out in clause 6.18.5 of the Rules in establishing our network tariffs. Table 7-4 below outlines our compliance.

Table 7-4: How we have addressed the pricing objective and pricing principles

	Pricing objective	How we have addressed the objective
	The tariff for direct control services for each of our customers should reflect the efficient costs of providing those services to those customers.	If the variable component of our tariffs is not above LRMC, we are transitioning them to LRMC. Residual costs are being allocated in a way that minimises customer impact and improves revenue stability.

	Pricing principle	How we have addressed the principle
1.	Revenue to be recovered must lie between the stand alone costs of serving customers and the avoidable costs of not serving those customers.	This has been proven in our LRMC model. In addition, each year our annual pricing proposal will demonstrate that the revenue expected to be recovered from our customers, for each network tariff class, lies between the stand alone costs of serving customers who belong to that class and the avoidable costs of not serving those customers. Our expected revenue for each tariff class is estimated to lie between our estimates of stand alone and avoidable cost
2.	Each tariff is to be based on LRMC	Attachment 5 - *Economic model from Houston-Kemp* sets out the economic model for calculating our LRMC and it is our intention to transition towards this approach. The approach which best suits our available inputs and network characteristics is the average incremental cost approach as described in Attachment 4 - *Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles from Houston-Kemp*.

	Pricing principle	How we have addressed the principle
3.	The revenue to be recovered from each network tariff must reflect the total efficient costs of providing services to the customers assigned to that tariff, and in a manner that minimises distortions to use of the network.	Our proposed tariffs seek to more closely align tariffs to our estimates of the LRMC, taking into account bill impacts on our customers. If the variable component of our tariffs is not above LRMC, we are transitioning them to LRMC as required in the Rules– in some cases this will take several years. Residual costs are being allocated in a way that minimises customer impact and improves revenue stability. See also section 7.3.
4.	Consideration to be given to the impact on customers of changes in network tariffs and tariffs should be designed so that they are reasonably capable of being understood by customers.	Our proposed tariff structures are unchanged from our current structures so they can be easily understood by customers. The bulk of our customers are residential and small businesses and will remain on the DBT with the option to move to TOU tariffs. We will publish brochures to help customers better understand TOU, demand and controlled load tariffs See also section 7.3.3.
5	Tariffs must be readily understood	Our current tariff structures have been in place for some time, and so are well understood by our customers. There is limited understanding amongst customers of more innovative tariff structures, for example demand tariffs, given the limited availability of Interval meters. We do not believe that this principle could be satisfied for these tariff structures at this time.
5.	Network tariffs must comply with any jurisdictional pricing obligations imposed by state or territory governments.	Our proposed tariffs take into account adjustments associated with the recovery of jurisdictional scheme costs.– see section 7.5.2.

COMPLIANCE CHECKLIST

The table below contains the National Electricity Rules relevant to the TSS and where in the TSS Essential Energy has addressed each requirement.

Rule	Requirement	Addressed in
6.8.2 (a)	A Distribution Network Service Provider must, whenever required to do so under paragraph (b), submit to the AER a regulatory proposal and a proposed tariff structure statement related to the distribution services provided by means of, or in connection with, the Distribution Network Service Provider's distribution system.	This entire TSS document and Attachments
6.8.2 (b) (1) to (2)	A regulatory proposal and a proposed tariff structure statement must be submitted (1) At least 17 months before the expiry of a distribution determination that applies to the *Distribution Network Service Provider*; or (2) If no distribution determination applies to the *Distribution Network Service Provider*, within three months after being required to do so by the *AER*.	Transitional requirement for submission to be made on 27 November 2015
6.8.2 (c) (7)	A regulatory proposal must include (but need not be limited to) the following elements: > A description (with supporting materials) of how the proposed tariff structure statement complies with the pricing principles for direct control services including: > A description of where there has been any departure from the pricing principles set out in paragraphs 6.18.5 (e) to (g); and > An explanation of how that departure complies with clause 6.18.5(c).	Section 7.6
6.8.2 (c1a)	The overview paper must also include a description of how the Distribution Network Service Provider has engaged with retail customers and retailers in developing the proposed tariff structure statement and has sought to address any relevant concerns identified as a result of that engagement.	Attachments 1 - *Overview of this TSS*
6.8.2 (d1)	The proposed tariff structure statement must be accompanied by an indicative pricing schedule.	Attachment 2 - *Indicative NUOS Pricing Schedule*
6.8.2 (d2)	The proposed tariff structure statement must comply with the pricing principles for direct control services.	This entire TSS document and Attachments
6.8.2 (e) and (f)	If more than one distribution system is owned, controlled or operated by a Distribution Network Service Provider, then, unless the AER otherwise determines, a separate regulatory proposal and a separate tariff structure statement are to be submitted for each distribution system. If, at the commencement of this Section, different parts of the same distribution system were separately regulated, then, unless the AER otherwise determines, a separate regulatory proposal and a separate tariff structure statement are to be submitted for each part as if it were a separate distribution system.	Not applicable
6.18.1A (a) 6.18.1A (a)(1)	A tariff structure statement of a Distribution Network Service Provider must include the following elements: (1) The tariff classes into which retail customers for direct control services will be divided during the relevant regulatory control period;	Section 6.2
6.18.1A (a)(2)	(2) The policies and procedures the Distribution Network Service Provider will apply for assigning retail customers to tariffs or reassigning retail customers from one tariff to another (including any applicable restrictions);	Section 3.5.6 and Attachment 6 - *Policies and procedures for assignment and reassignment of tariffs*
6.18.1A (a)(3)	(3) The structures for each proposed tariff;	Section 6.3 and Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.1A (a)(4)	(4) The charging parameters for each proposed tariff; and	

Rule	Requirement	Addressed in
6.18.1A (a)(5)	A description of the approach that the Distribution Network Service Provider will take in setting each tariff in each pricing proposal of the Distribution Network Service Provider during the relevant regulatory control period in accordance with clause 6.18.5.	Section 6.6 and section 7
6.18.1A (b)	A tariff structure statement must comply with the pricing principles for direct control services.	This entire TSS document and Attachments
6.18.1A (e)	A tariff structure statement must be accompanied by an indicative pricing schedule which sets out, for each tariff for each regulatory year of the regulatory control period, the indicative price levels determined in accordance with the tariff structure statement.	Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.3 (b)	Each customer for direct control services must be a member of one or more tariff classes.	Section 6.2
6.18.3 (c)	Separate tariff classes must be constituted for retail customers to whom standard control services are supplied and retail customers to whom alternative control services are supplied (but a customer for both standard control services and alternative control services may be a member of 2 or more tariff classes).	Sections 6.3 and 6.7
6.18.3 (d) (1) to (2)	A tariff class must be constituted with regard to: (1) The need to group retail customers together on an economically efficient basis; and (2) The need to avoid unnecessary transaction costs.	Sections 3.5.1 and 6.2
6.18.4 (a)	In formulating provisions of a distribution determination governing the assignment of retail customers to tariff classes or the re-assignment of retail customers from one tariff class to another, the AER must have regard to the following principles: (1) Retail customers should be assigned to tariff classes on the basis of one or more of the following factors: (i) The nature and extent of their usage; (ii) The nature of their connection to the network; (iii) Whether remotely-read interval metering or other similar metering technology has been installed at the retail customer's premises as a result of a regulatory obligation or requirement; (2) Retail customers with a similar connection and usage profile should be treated on an equal basis; (3) However, retail customers with micro-generation facilities should be treated no less favourably than retail customers without such facilities but with a similar load profile; (4) A Distribution Network Service Provider's decision to assign a customer to a particular tariff class or to re-assign a customer from one tariff class to another should be subject to an effective system of assessment and review.	Sections 3.5.1 and 6.2 and Attachment 6 - *Policies and procedures for assignment and reassignment of tariffs*
6.18.4 (b)	If the charging parameters for a particular tariff result in a basis of charge that varies according to the usage or load profile of the customer, a distribution determination must contain provisions for an effective system of assessment and review of the basis on which a customer is charged.	Section 3.5.6 and Attachment 6 - *Policies and procedures for assignment and reassignment of tariffs*
6.18.5 (a)	The network pricing objective is that the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer.	Section 7 and Attachments 4 - *Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles from Houston-Kemp* and 5 - *Economic model from Houston-Kemp*
6.18.5 (b)	Subject to paragraph (c), a Distribution Network Service Provider's tariffs must comply with the pricing principles set out in paragraphs (e) to (j).	
6.18.5 (c) (1) to (2)	A Distribution Network Service Provider's tariffs may vary from tariffs which would result from complying with the pricing principles set out in paragraphs (e) to (g) only: (1) To the extent permitted under paragraph (h); and (2) To the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).	

Rule	Requirement	Addressed in
6.18.5 (d)	A Distribution Network Service Provider must comply with paragraph (b) in a manner that will contribute to the achievement of the network pricing objective.	Section 7 and Attachments 4 - *Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles from Houston-Kemp* and 5 - *Economic model from Houston-Kemp*
6.18.5 (e) (1) to (2)	For each tariff class, the revenue expected to be recovered must lie on or between: (1) An upper bound representing the stand alone cost of serving the retail customers who belong to that class; and (2) A lower bound representing the avoidable cost of not serving those retail customers.	
6.18.5 (f) (1) to (3)	Each tariff must be based on the long run marginal cost of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to: (1) The costs and benefits associated with calculating, implementing and applying that method as proposed; (2) The additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network; and (3) The location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network	
6.18.5 (g) (1) to (3)	The revenue expected to be recovered from each tariff must: (1) Reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff; (2) When summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider; and (3) Comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).	
6.18.5 (h) (1) to (3)	A Distribution Network Service Provider must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the Distribution Network Service Provider considers reasonably necessary having regard to: (1) The desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period); (2) The extent to which retail customers can choose the tariff to which they are assigned; and (3) The extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions.	Section 6.5 & Attachment 4 - *Estimation of Long Run Marginal Cost and Other Concepts Related to the Distribution Pricing Principles from Houston-Kemp*
6.18.5 (i) (1) to (2)	The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to: (1) The type and nature of those retail customers; and (2) The information provided to, and the consultation undertaken with, those retail customers.	Sections 5.3.1 and 7.4
6.18.5 (j)	A tariff must comply with the Rules and all applicable regulatory instruments.	Section 7.6
6.18.6 (a)	This clause applies only to tariff classes related to the provision of standard control services.	Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.6 (b)	The expected weighted average revenue to be raised from a tariff class for a particular regulatory year of a regulatory control period must not exceed the corresponding expected weighted average revenue for the preceding regulatory year in that regulatory control period by more than the permissible percentage.	

Rule	Requirement	Addressed in
6.18.6 (c) (1) to (2)	The permissible percentage is the greater of the following: (1) The CPI-X limitation on any increase in the Distribution Network Service Provider's expected weighted average revenue between the two regulatory years plus 2%; Note: The calculation is of the form (1 + CPI)(1 – X)(1 + 2%) (2) CPI plus 2%. Note: The calculation is of the form (1 + CPI)(1 + 2%)	Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.6 (d) (1) to (4)	In deciding whether the permissible percentage has been exceeded in a particular regulatory year, the following are to be disregarded: (1) The recovery of revenue to accommodate a variation to the distribution determination under rule 6.6 or 6.13; (2) The recovery of revenue to accommodate pass through of designated pricing proposal charges to retail customers; (3) The recovery of revenue to accommodate pass through of jurisdictional scheme amounts for approved jurisdictional schemes; and (4) The recovery of revenue to accommodate any increase in the Distribution Network Service Provider's annual revenue requirement by virtue of an application of a formula referred to in clause 6.5.2(l).	
6.18.7 (a)	A pricing proposal must provide for tariffs designed to pass on to retail customers the designated pricing proposal charges to be incurred by the Distribution Network Service Provider.	Sections 3.3 and 6 and Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.7 (b)	The amount to be passed on to retail customers for a particular regulatory year must not exceed the estimated amount of the designated pricing proposal charges adjusted for over or under recovery in accordance with paragraph (c).	
6.18.7 (c) (1) to (3)	The over and under recovery amount must be calculated in a way that: (1) Subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER in the relevant distribution determination for the Distribution Network Service Provider; (2) Ensures a Distribution Network Service Provider is able to recover from retail customers no more and no less than the designated pricing proposal charges it incurs; and (3) Adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.	Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.7 (d) (1) to (3)	Notwithstanding anything else in this clause 6.18.7, a Distribution Network Service Provider may not recover charges under this clause to the extent these are: (1) Recovered through the Distribution Network Service Provider's annual revenue requirement; (2) Recovered under clause 6.18.7A; or (3) Recovered from another Distribution Network Service Provider.	
6.18.7A (a)	A pricing proposal must provide for tariffs designed to pass on to customers a Distribution Network Service Provider’s jurisdictional scheme amounts for approved jurisdictional schemes.	Section 7.5.2and Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.7A (b)	The amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of jurisdictional scheme amounts for a Distribution Network Service Provider's approved jurisdictional schemes adjusted for over or under recovery in accordance with paragraph (c).	
6.18.7A (c) (1) to (3)	The over and under recovery amount must be calculated in a way that: (1) Subject to subparagraphs (2) and (3) below, is consistent with the method determined by the AER for jurisdictional scheme amounts in the relevant distribution determination for the Distribution Network Service Provider, or where no such method has been determined, with the method determined by the AER in the relevant distribution determination in respect of designated pricing proposal charges;	

Rule	Requirement	Addressed in
	(2) Ensures a Distribution Network Service Provider is able to recover from customers no more and no less than the jurisdictional scheme amounts it incurs; and (3) Adjusts for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant distribution determination for the relevant regulatory year.	
6.18.7A (d) (1) to (2)	A scheme is a jurisdictional scheme if: (1) The scheme is specified in paragraph (e); or (2) The AER has determined under clause paragraph (l) that the scheme is a jurisdictional scheme, and The AER has not determined under paragraph (u) that the scheme has ceased to be a jurisdictional scheme.	Section 7.5.2and Attachment 2 - *Indicative NUOS Pricing Schedule*
6.18.7A (e) (1) to (3)	For the purposes of paragraph (d)(1), the following schemes are jurisdictional schemes: (1) Schemes established under the following laws of participating jurisdictions: (i) Electricity Feed-in (Renewable Energy Premium) Act 2008 (ACT); (ii) Division 3AB of the Electricity Act 1996 (SA); (iii) Section 44A of the Electricity Act 1994 (Qld); (iv) Electricity Industry Amendment (Premium Solar Feed-in Tariff) Act 2009 (Vic); (2) The Solar Bonus Scheme established under the Electricity Supply Act 1995 (NSW); and (3) The Climate Change Fund established under the Energy and Utilities Administration Act 1987 (NSW).	
6.19.2 (a)	Subject to the Law and the Rules, all information about a Service Applicant or Distribution Network User used by Distribution Network Service Providers for the purposes of distribution service pricing is confidential information.	Requirement adhered to throughout entire TSS
6.19.2 (b)	No requirement in this Chapter 6 to publish information about a tariff class is to be construed as requiring publication of information about an individual retail customer.	
No applicable Rule	Essential should make claims for confidentiality in accordance with the AER's Confidentiality Guideline.	