SA Power Networks

Attachment 17

Tariff Structure Statement

2020-25 Regulatory Proposal

31 January 2019

This section outlines:

- the proposed 2020-25 tariff structures and indicative prices to recover the allowed Standard Control Services revenue from our customers; and
- indicative prices for the Alternative Control Services we will provide our customers during the 2020-25 Regulatory Control Period.

Company information

SA Power Networks is the registered Distribution Network Service Provider (**DNSP**) for South Australia. For information about SA Power Networks visit www.sapowernetworks.com.au

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Disclaimer

This document forms part of SA Power Networks' Regulatory Proposal (**the Proposal**) to the Australian Energy Regulator (**AER**) for the 1 July 2020 to 30 June 2025 regulatory control period (2020-25 **RCP**). The Proposal and its attachments were prepared solely for the current regulatory process and are current as at the time of lodgment.

This document contains certain predictions, estimates and statements that reflect various assumptions concerning, amongst other things, economic growth and load growth forecasts. The Proposal includes documents and data that are part of SA Power Networks' normal business processes, and are therefore subject to ongoing change and development.

Whilst care was taken in the preparation of the information in this Regulatory Proposal, and it is provided in good faith, SA Power Networks, its officers and shareholders accept no responsibility or liability for any loss or damage that may be incurred by any person acting in reliance on this information or assumptions drawn from it for a different purpose or in a different context.

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Note

This attachment forms part of our Proposal for the 2020-25 RCP. It should be read in conjunction with the other parts of the Proposal.

Our Proposal comprises the overview and attachments listed below, and the supporting documents that are listed in Attachment 18:

Document	Description
	Regulatory Proposal overview
	Customer and stakeholder engagement report
Attachment 1	Annual revenue requirement and control mechanism
Attachment 2	Regulatory asset base
Attachment 3	Rate of return
Attachment 4	Regulatory depreciation
Attachment 5	Capital expenditure
Attachment 6	Operating expenditure
Attachment 7	Corporate income tax
Attachment 8	Efficiency benefit sharing scheme
Attachment 9	Capital expenditure sharing scheme
Attachment 10	Service target performance incentive scheme
Attachment 11	Demand management incentives and allowance
Attachment 12	Classification of services
Attachment 13	Pass through events
Attachment 14	Alternative Control Services
Attachment 15	Negotiated services framework and criteria
Attachment 16	Connection policy
Attachment 17	***Tariff Structure Statement***
Attachment 18	List of Proposal documentation

Contents

List of Figures

List of Tables

17 Tariff Structure Statement

17.1 Overview

This attachment outlines:

- ***Why we have tariffs***: Tariffs recover the revenue we are allowed for the provision of Standard Control Services (**SCS**) to our customers. They recover the costs to plan, construct, operate and maintain the shared distribution network. Tariff reform is proposed to help to keep future distribution network costs down by improving customer use of the existing network and reducing the need to increase network capacity in the future.
- ***What our tariffs do:*** Our pricing needs to signal, via more cost-reflective tariffs, the cost of building and maintaining a network to better manage customer demand peaks and troughs. Increasingly the troughs are being formed by surplus energy generated by solar on South Australian rooftops. Our tariffs also need to equitably share network service costs amongst all users (residential and business).
- ***Who will benefit from the tariffs:*** We already have cost-reflective 'demand-based tariffs' for our largest customers. The tariff reform process is now looking to influence how households and small businesses use energy. However, our charges are billed to customers' retailers and it will be up to retailers how they pass on our charges to their customers.
- ***What the proposed tariff structures are:*** Interval meters measure electricity consumed at half-hourly intervals and enable more cost-reflective tariffs than the old 'accumulation' meters which only record total consumption, generally over a 90-day period. Large businesses have had interval meters and 'demand' tariff structures for many years. However, the majority of residential and small business customers don't have interval meters. Their legacy meters (Type 6) require that their existing tariff structures continue until the meter is changed. Time-of-Use (**ToU**) tariff structures are proposed for residential and small business customers, who have interval meters.
- ***When the tariffs will apply:*** About 13% of residential customers and 15% of business customers now have interval meters. We expect this to grow to 45% by 2025 as all new and replacement meters must be of the new interval meter type including small business starts. All existing customers with interval meters will be assigned to the new cost-reflective tariffs as will all new customers. Other existing customers will be assigned when they get a new or replacement meter.
- ***How customers will benefit:*** If retailers pass these tariffs through to customers, some customers will be motivated to change consumption patterns and reduce their individual bills. Other customers will incorporate these pricing changes into possible investments in equipment including more efficient plant and distributed energy resources (**DER**). This will help to lower the future electricity price for all customers by helping to reduce the impact of demand peaks and troughs on the network. This will lower network expenditure in the longer term and increase the amount of low-cost renewable energy distributed locally, translating to future lower energy and network prices.

This Attachment refers to different metering types. Meter types impact the tariff options for small customers. The meter types are:

- Type 4 (interval meter, typically remotely read). Retailers arrange for Type 4 meters to be installed wherever a new meter is required (including meter replacement).
- Type 5 (interval meter, typically read manually by a meter reader). These meters were installed at some customer premises over the last decade but are not permitted to be installed today.
- Type 6 (accumulation meter, read manually by a meter reader). These meters measure energy use similar to an odometer in a car. It measures energy used to date.
- Type 7 (unmetered supplies). Special arrangements are used are used for the measurement of energy used by unmetered supplies such as street lights.

Type 6 meters can have different meter components which impact on tariffs used. For example:

- The meter may be single-rate or, for some small businesses, it may be two-rate enabling peak/off-peak metering
- The meter may have a separate register which records and controls a separate register which records and controls a separate electricity circuit typically used for hot water heating (off-peak controlled load, or **OPCL**). Hot water OPCL is different to two-rate off-peak.
- The meter may be able to separately measure import and export of electricity. Customers with solar need to have such metering capability (Type 4 meters provide this today for new applicants).

Small customers will move away from legacy Type 6 meters to interval Type 4 meters over time.

Background

This Tariff Structure Statement (**TSS**) provides details on the pricing structure by which SA Power Networks recovers the revenue allowed by the Australian Energy Regulator (**AER**).

This TSS has been prepared by SA Power Networks under the requirements of Chapter 6 of the National Electricity Rules (**NER,** or **the Rules**). It provides details of our proposed approach to network tariffs over the period from July 2020 to June 2025.

When developing tariffs and tariff structures, our aim is to better reflect the costs incurred by SA Power Networks that result from customer decisions to use electricity at specific times and locations. Our forward-looking costs are primarily driven by a combination of asset replacement and network augmentation works required to continue to provide a safe and reliable network that is capable of responding to periods of peak demand and periods of significant solar generation.

The purpose of 'cost-reflective' tariffs is to provide a pricing signal to retailers and their customers during periods of peak demand, so that customers can be appropriately rewarded if they respond by moving some of their electricity usage out of the peak demand period. Reducing peak demand will reduce the need for future augmentation investment and future network prices will be lower as a consequence. The cost-reflective tariffs also provide better signalling of future costs for those customers wishing to use more electricity. The tariffs also help manage the period of the 'solar-trough' where significant amounts of solar generation distributed throughout the network are supplying power to the system and creating reverse flows in parts of our network during some parts of the day.

The pricing principles in the NER require us to demonstrate an incremental movement towards more cost-reflective tariffs in our TSS, whilst taking into consideration customer pricing impacts. To help us understand our customers' views on pricing impacts, we undertook extensive customer and stakeholder engagement throughout the development of our TSS.

We have listened to feedback from our customers and the AER's requirement to continue tariff reform. We believe there is a need to empower the customer and simplify the tariffs so that customers can understand and respond with changes to their consumption of energy when and where they can. Our last regulatory proposal considered demand-based tariffs for residential customers, but this option was not pursued by customers and retailers in the 2017 revised TSS. Our analysis and consultation with our customers suggests that a simplified structure involving a ToU tariff will provide the appropriate incentives to customers to assist in managing costs within the network. Similar feedback was received from small business, who also have high levels of diversity like residential, which makes ToU a preferable and simpler approach compared to demand. This option exploits an increasing number of interval meters in residential and small business customers initiated by the 'Power of Choice' rule change introduced in 2017[1].

[1] *Australian Energy Markets Commission (**AEMC**) changes to the National Electricity Rules.*

The changes proposed in this TSS

The changes proposed in this TSS respond to the customer-led and environmental changes we are experiencing whilst simplifying the tariff structures by:

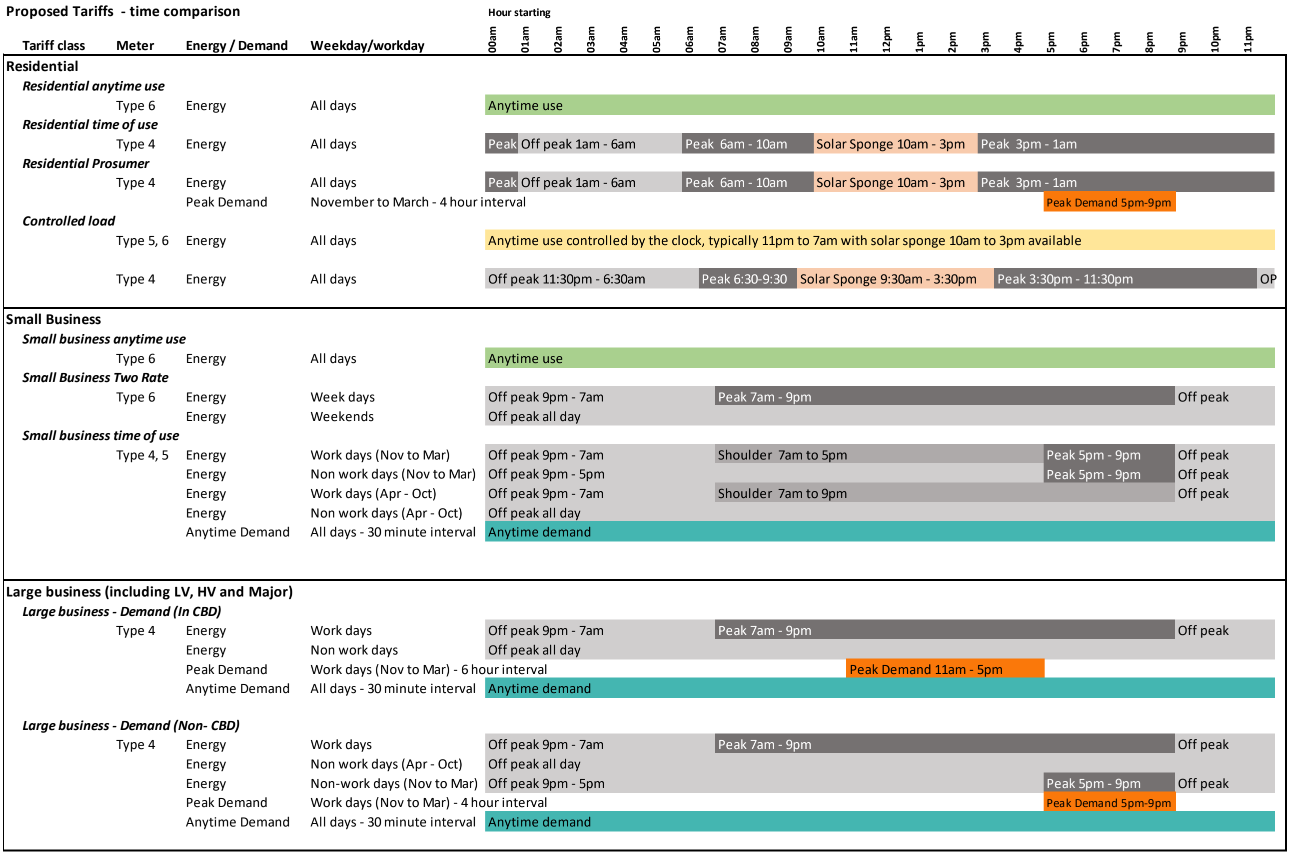
- continuation of a fixed 'supply' charge for all customers but with some increase in the proportion;
- removing the inclining residential block tariffs which charge more for increases in energy consumption in a month or quarter, irrespective of when energy was used during that period and applying a flat anytime use charge for those customers with accumulation (Type 6) meters;
- introducing a ToU residential tariff for those with interval meters with peak times (Type 4 or Type 5) identified in the morning and evening while also recognising the 'solar trough' (peak times are determined to be 6:00am to 10:00am and 3:00pm to 1:00am, and a 'solar trough' will have a very low price between 10:00am and 3:00pm);
- introducing an optional 'Prosumer' demand tariff for residential customers with a Type 4 interval meter where the demand is measured as the highest average demand over a four-hour period 5:00pm to 9:00pm each month for November through to March;

- introducing a ToU tariff for small business customers with interval meters where peak is defined as 5:00pm to 9:00pm on work days, and non-work days from November to March (shoulder and off-peak price elements are also used reflecting typical business hours ie 7:00am to 9:00pm work days at a higher price);
- introducing a TOU tariff with maximum demand charge that would apply to those small businesses using more than 70kVA of demand;
- introducing a locational large business demand tariff for the central business district (**CBD**) of Adelaide with a six-hour demand window between 11:00am to 5:00pm on workdays from November to March;
- having a different demand window for non-CBD large business which incorporates a four-hour demand peak window between 5:00pm and 9:00pm any day from November to March reflecting the impact of solar on coincident peak demand.

The analysis presented in this TSS demonstrates that work day and non-work day seasonal demands are not sufficiently different to drive tariff structures in all locations of South Australia, except for the CBD.

The tariffs proposed are set out in tables presented in Section 17.10. Part of our response to the development of cost-reflective tariffs recognises the times when our network has congestion and times when it has capacity. The time of the day (and days of the year) where we measure peak energy and peak or anytime demand volumes to which the tariffs are applied is summarised in Figure 17.1.

Figure 17.1: SA Power Networks' tariff peak and off-peak times



In summary:

- Whilst peak demand is still a consideration in building network to respond to customer needs, it is no longer a key driver for how we manage our network and the associated costs we incur to provide SCS.
- The primary consideration in network response over the 2020-25 RCP, particularly for residential networks, is the need to manage the uptake of solar generation, or DER, which has created a 'solar trough'. During this 'solar trough', there are significant reverse power flows in our network where energy generated by customers with solar is required to be transported and managed by our network. The distribution network has a finite capacity to host these power flows before technical operating limits are breeched which can lead to 'high voltage' and other issues.
- The 'Power of Choice' rule changes introduced in December 2017 have provided a mechanism by which residential and small business customers can access a Type 4 interval meter, which allows for new tariffs to be offered for a growing population of interval metered customers.
- As a consequence of these changes, we are moving to more cost-reflective tariffs to keep future network costs down by:
  - improving use of the existing network; and
  - reducing the need to invest in additional network capacity in the future.
- Our proposed cost-reflective tariffs for 2020-25 are set out in summary as:
  - ToU tariffs for residential and small business customers with interval meters;
  - 'Prosumer' tariff, a demand tariff, is also available as an optional tariff for those residential customers that want to better manage their consumption;
  - small businesses anytime demand component has been included for those with significant demands of greater than 70kVA; and
  - large business tariffs features have been simplified and refined.
- Our new cost-reflective tariffs will apply to all existing customers with interval meters and as customers migrate to a new or replacement meter (from July 2020). We are not proposing that a

12-month data honeymoon applies before reassignment of small customers to a ToU tariff as the price impact does not warrant the added cost involved.

Whilst the peak demand is not the key driver of the network growth, peak demand will be addressed by:

- Residential customers replacing older air-conditioning plant with more efficient units.
- Residential prosumers who choose to embrace the peak signalling, including using their batteries to discharge during peak periods.
- Small business with interval meters responding to the new 5:00pm to 9:00pm peak rate in summer, with flexible loads being moved away from this coincident peak.
- Large business outside of the CBD responding to the monthly measurement of demand between 5:00pm and 9:00pm, during the months of November to March.
- Large business in the CBD responding to the monthly measurement of demand between 11:00am and 5:00pm on work days during the months of November to March.

Localised demand and the incremental costs of individual customers on the network will be addressed by:

- Increasing the supply charge of residential and small business customers.
- Using an anytime demand charge for small business with interval meters and demand greater than 70kVA (whilst recognising the diversity of demand at the Low Voltage (**LV**) level for such customers).
- Separating out an explicit anytime demand charge for large businesses, aimed at recovering the costs of local supply assets.

This proposed tariff structure will also respond to, and influence customer behaviour associated with the new demands of electric vehicles (**EV**). Whilst not a current driver of network constraints and therefore costs today, we expect that EVs will introduce new loads in the 2020-25 period. The proposed tariff structure and in particular the timing of peak and off-peak consumption should influence the timing and the nature of charging of these vehicles in the future in a way that manages network costs.

17.2 Introduction

Tariffs represent the pricing structure by which SA Power Networks recovers the revenue allowed by the AER to provide SCS – for use of the shared network.

Tariffs set the price for services that are provided by the electricity distribution network and are differentiated for customers who use the network in different ways.

There is some cost-reflectivity within existing current tariff structures, as the current tariff already reflects the size of the customer's electricity usage and how much of the network they use. There is some cross subsidy as well. Whilst it costs more to provide electricity to customers in country areas compared with urban areas, State Government policy requires a State-wide price for each small customer within the same customer group.

Our tariffs also consider various attributes such as the density of customers within a network, the type and size of the electricity supply, when electricity is used, the peak demand and the metering that is available to collect information on a customer's use of the network. These matters influence the tariffs that can be offered to customers.

This document should be read in conjunction with 'Chapter 7 – Tariff Structure', of our Regulatory Proposal Overview Document. All dollars are June, $2020, million unless specified otherwise. The structure and content of this TSS document is outlined in Table 17.1.

Table 17.1: Tariff Structure Statement - document structure

Section	Title	Context
17.2	Introduction	Describes the layout of this document
17.3	Characteristics of our network – what influences pricing and our forecasts	Sets out a description of our network, our operating environment, customer profiles and the demand forecasts by the Australian Energy Market Operator (**AEMO**).
17.4	The key challenges we are trying to address	Provides an outline of principle changes in technology and the change in the timing of peak demand, which drives network behaviour and therefore influences tariff design.
17.5	Customer impact principles	Describes the principles of tariff design that are important to our customers, and therefore drive the development of tariffs.
17.6	AER directions	Sets out the AER directions on tariff development which we need to apply.
17.7	Types of tariffs and tariff redesign strategies	A brief description of the types of tariffs that have been used in the past and what can be used for current development within the principles.
17.8	Customer engagement	A summary of the customer engagement outcomes with respect to tariffs and how we have responded to the matters raised in our engagement process.
17.9	Tariff classes	Defines the customer classes for which tariffs are developed.
17.10	How we develop the tariffs for the 2020-25 Regulatory Control Period	A description of the tariffs for the different tariff classes, how these have been developed within the customer impact principles, and the technology available to meter customer demand and energy consumption.
17.11	Assigning customers to tariff classes	The process of assigning customers to tariffs and the National Electricity Rules with which we need to comply with in tariff assignment including opt-in and opt-out provisions.
17.12	What do these tariffs mean for customers	A brief assessment of the changes to tariffs and what this means for customers.
17.13	Other considerations	Considerations for future tariff design.
17.14	Pricing methodology	A summary of the compliance with the customer principles and the National Electricity Rules.

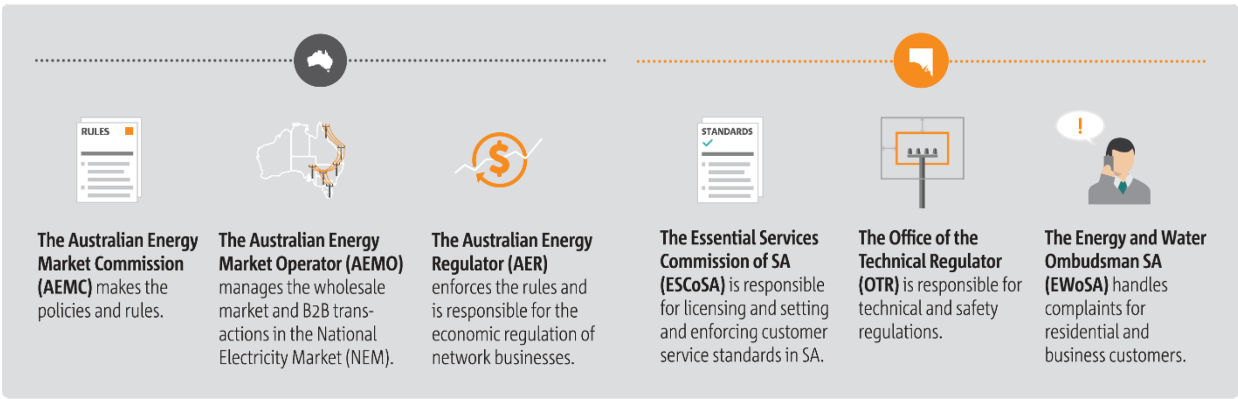
17.3 Characteristics of our network – what influences pricing and our forecasts

This section of our TSS provides contextual information about SA Power Networks and our customers.

17.3.1 Who we are

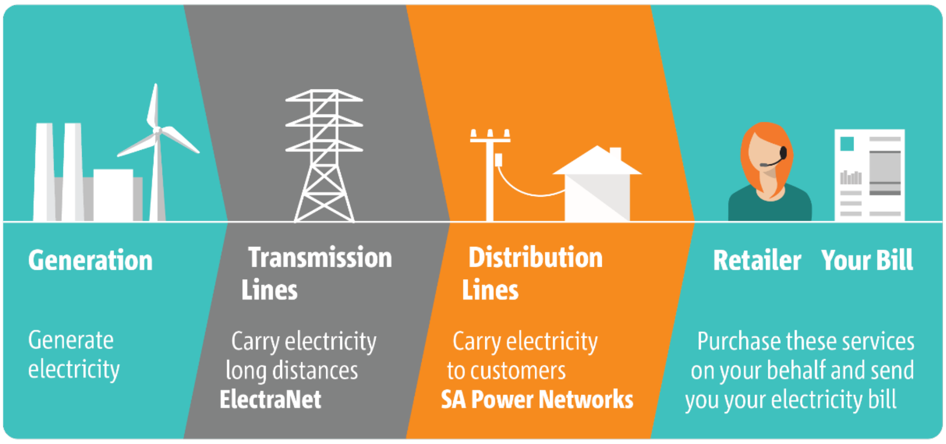
SA Power Networks is a Distribution Network Service Provider (**DNSP**) which operates within the National Electricity Market (**NEM**). We are governed by a number of agencies rules and regulations at the National and State levels as shown in **Figure 17.2** below.

Figure 17.2: SA Power Networks' governing agencies



The electricity supply chain consists of generation, transmission, distribution and retailers as shown in **Figure 17.3**. In South Australia, ElectraNet provides the electricity transmission services and we provide the electricity distribution services to around 860,000 customers ranging from isolated farms in rural areas to industry precincts, regional and metropolitan residential homes, businesses and city centres.

Figure 17.3: Electricity supply chain



17.3.2 Our network

SA Power Networks' distribution network serves the state of South Australia, with a service territory of about 178,000 km^2, and with a coastline of over 5,000 km. The network's route length extends to more than 82,000 km, with approximately 20% underground. The network includes 416 zone substations, 77,800 distribution transformers, approximately 647,000 poles and 1.1 million meters. The extent of SA Power Networks' operations in South Australia is shown in Figure 17.4.

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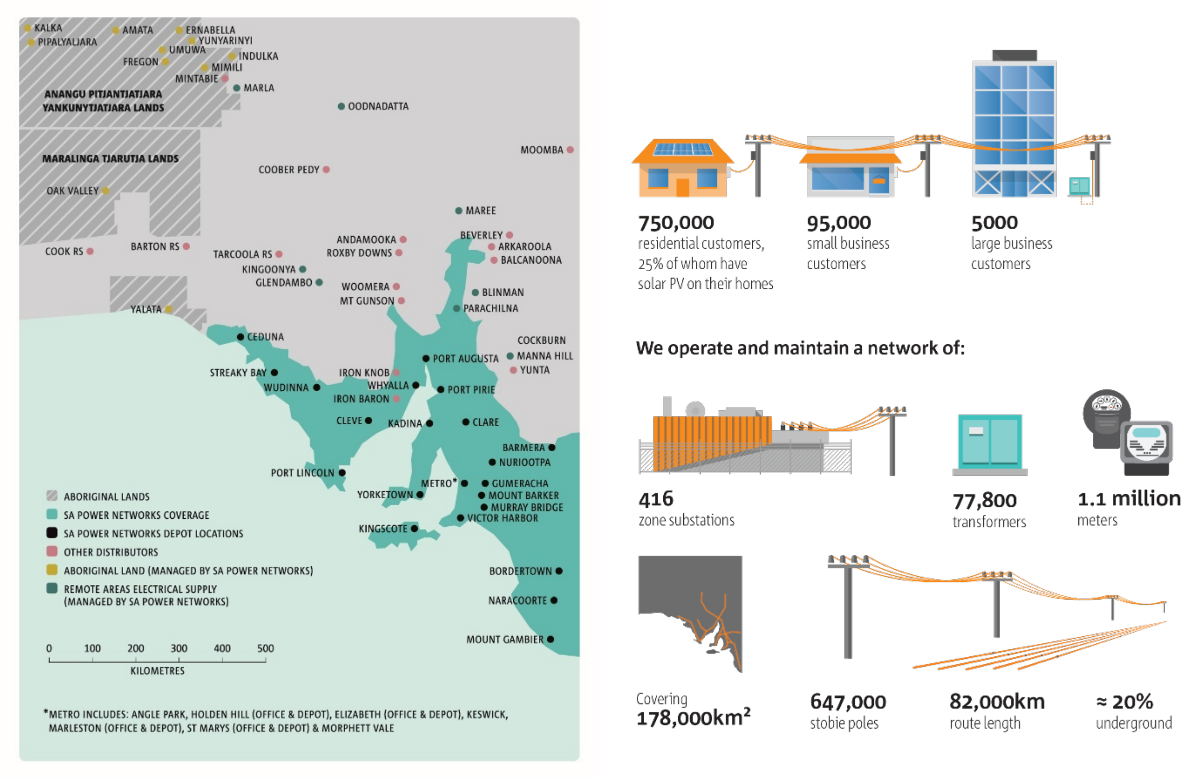
Figure 17.4: SA Power Networks' Service Area



The South Australian distribution network is a predominantly three-phase system, with single-phase used mostly in rural and remote areas. A sub-transmission network supplies and links zone substations, operating at 66 kilovolts (**kV**) and 33kV. In rural and remote areas, a single-phase system operates at 19kV. 30% of the network is comprised of these long 'single wire earth return' (**SWER**) lines. In higher density rural and urban locations, the three-phase feeder system operates at 11 kV. The standard low voltage customer supply is 230V at 50Hz.

With the exception of much of the coastal area and the hinterland, South Australia is very sparsely settled. Approximately 70% of our customers reside in the greater Adelaide metropolitan area, including the great majority of business and commercial customers. However, the extensive area serviced by our distribution system results in 70% of the network powerline infrastructure delivering energy to the remaining 30% of customers. Compared with other states, there are relatively few regional centres, and they are generally small and sparsely located. As a result, the average customer density across the State is very low.

17.3.3 Our operating environment

Adelaide and much of South Australia has a dry climate featuring greater extremes of summer temperature than most other Australian capitals. Extended periods of heatwave conditions can occur in summer (November 2009, January 2014 and January 2019 are recent examples of extended heatwaves).

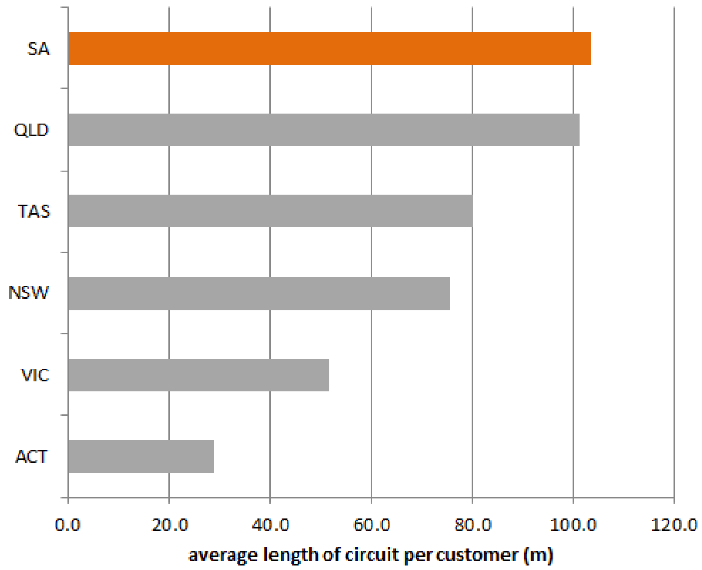
During these heatwave periods, summer daytime temperatures can exceed 40^0C for several days in a row and overnight minimums can remain above 30^0 C for some of those days.

Our distribution network needs to respond to the peak demands experienced in these heatwave conditions, and during a time when solar is not performing at its best due to heat constraints or when the sun is not shining, and after the key solar generation period of the day.

17.3.4 Our customer density

As mentioned above, we supply electricity to around 860,000 customers ranging from isolated farms in rural areas to industry precincts, regional and metropolitan residential homes, businesses and city centres. The average customer density per kilometre of distribution line in South Australia is the lowest in the NEM as indicated in Figure 17.5. Put another way, we provide more network per customer than the other regions. The only distributors with lower customer densities are the largely rural networks operated by Ergon in Queensland and Essential Energy in NSW. South Australia is the only mainland NEM state to have a single distribution business for the entire state.

Figure 17.5: Circuit length per customer for each state



Source: SA Power Networks Analysis

The South Australian Government has imposed a requirement on SA Power Networks to maintain State-wide pricing for small customers (with annual consumption not exceeding 160 MWh per annum)[2]. All of SA Power Networks' distribution tariffs are averaged[3]. Large business customers in the CBD of Adelaide will have different tariffs to those in the rest of South Australia reflecting the time of local peak demand.

Without this 'country equalisation scheme', cost-reflective network charges would mean a significant increase in network costs for many rural customers. This long-standing policy commitment from the Government effectively precludes us from incorporating locational price signals into our tariffs for small customers[4] and so pricing reform in South Australia must be primarily based on peak demand or the ToU.

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[2] *South Australian Treasurer, Electricity Act 1996 Section 35B Electricity Pricing Order, 11 October 1999. Cl 7.3 (f)-(h)*

[3] For larger business customers with energy consumption in excess of 40 GWh or a demand greater than 10 MW, locational transmission use of system (**TUoS**) charges apply.

[4] However, large sub-transmission and zone substation customers are subject to locational pricing.

17.3.5 Our customer demand profile

In the past few decades, the South Australian climate has led to an extraordinary demand for air conditioning. Over 90% of homes are air-conditioned with the air-conditioned floor space of these homes continuing to increase, albeit with more efficient air-conditioning plant. The consequent high peak network demand occurs for only a small part of the year. At other times in summer, milder weather often occurs which requires no air conditioning in most homes.

Capacity for these extremely 'peaky' conditions such as those during heatwaves requires network assets that are under-utilised during much of the year, driving distribution costs higher on a per unit of energy served basis than comparable interstate networks.

A more recent development and one that has had a significant impact within South Australia is the uptake of solar systems by small customers. More than 30% of residential customers in South Australia now have solar systems operating, reducing their use of network delivered energy when the sun is shining. The incentives of the solar Feed-in Tariff (**FiT**) schemes have been popular in the past, and customers have responded to the incentives provided. The take up of solar has reduced the growth in peak demand. Demand last peaked in our network 10 years ago in 2009.

17.3.6 AEMO analysis

AEMO said in its November 2018 South Australian Electricity Report[5] that:

- Rooftop solar contributed 8.2%[6] of the local generation mix in South Australia for 2017-18, with more than 30% of dwellings in South Australia now having rooftop solar systems installed. (Analysis provided by the Australian PV Institute). AEMO estimated that rooftop solar contributed 1,162 GWh for the 2017-18 year.[7]
- "Rooftop PV contributed 51 MW more at the underlying peak in 2017-18 than it did in the previous year delivering 495 MW at the time of peak underlying demand (4.30 pm Adelaide time) and moving the time of peak network demand from 6:30 pm in the previous year to 7.30 pm Adelaide time." [8]
- "This consumer activity, combined with energy efficiency savings, kept annual operational consumption in South Australia flat at 12,203 GWh in 2017-18, despite underlying population growth. It is expected to stay at a similar level for the next 10 years." [9]

Because the maximum demand has now moved into the evening, further growth in solar is unlikely to have an impact on the daily peak unless there is growth in and exploitation of storage.

AEMO expects the level of maximum demand from the network to rise as population grows because the effects of solar growth are unlikely to impact on the daily peak.

Among the NEM regions, South Australia has the highest proportions of each of gas, wind and rooftop solar generation.

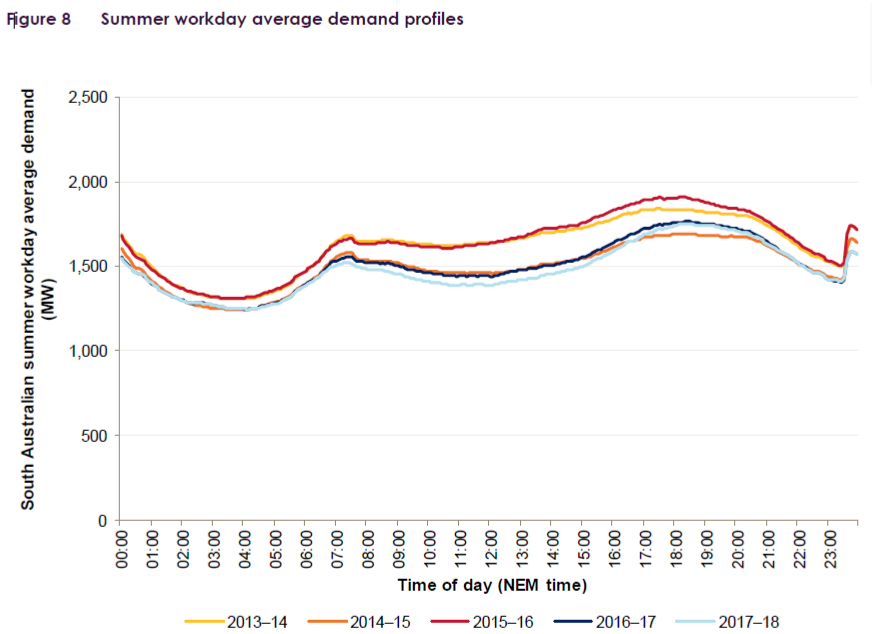
South Australia's minimum demand for 2017-18 was 561MW[10] recorded at 1:30pm on Sunday 5 November 2017 (note that the AEMO report quoted 645.6 MW for 5 November 2017, which would include adjustment for non-scheduled generation despatched). On 2 December 2018 a lower minimum of 520MW was recorded at 13:30pm.

[5] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2018/2018-South-Australian-Electricity-Report.pdf
[6] *ibid page 28*
[7] *ibid page 22*
[8] *ibid page 4*
[9] *ibid page 4*
[10] Total net demand from the pool

AEMO makes the following observations over the previous five years in respect to the South Australian average summer demands.

The AEMO data in Figure 17.6 shows a general decline in demand over the past few years except for 2015-16 when South Australia experienced heatwave conditions and record-breaking day time temperatures. The 2017-18 demand shows a reduction on the 2012-13 demand, influenced by energy efficiency and solar offsets.

Figure 17.6: AEMO Figure 8 of 2018 report – Daily Demand Profiles



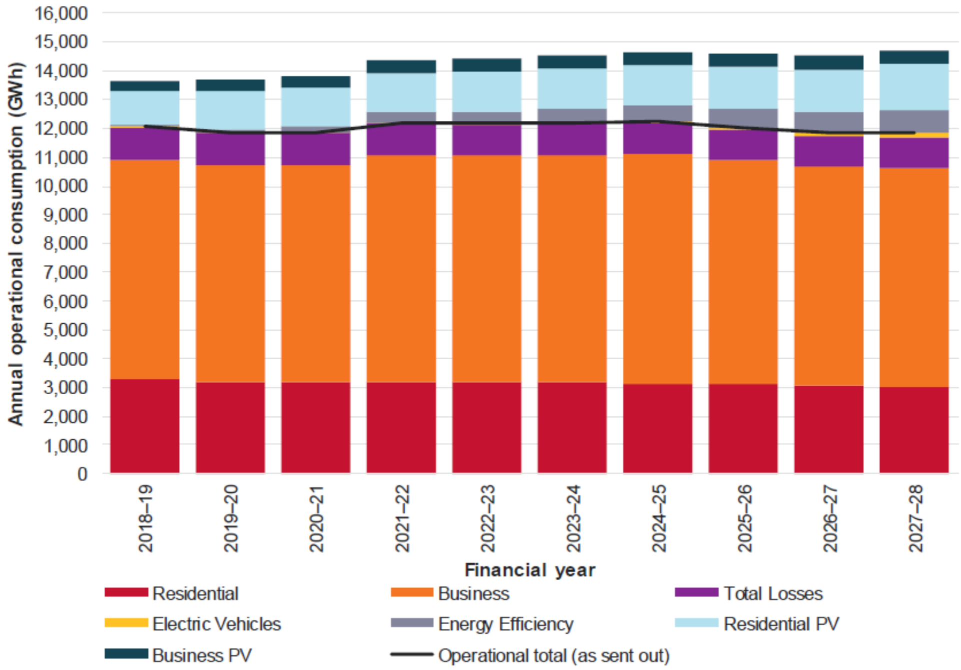
Source: AEMO South Australian Electricity Report 2018, Page 25

Figure 17.7 demonstrates the impact of energy efficiency and rooftop solar on the declining demand in South Australia. EVs are not expected to have a marked change over the forecast period. The energy efficiency, residential solar and business solar represent energy displaced from scheduled generation. This data comes from the AEMO Electricity Statement of Opportunities (**ESOO**)[11] and has been used by SA Power Networks to determine energy volumes forecasts for 2019-20 and for the 2020-25 RCP.

[11] AEMO 2018 National Electricity Market Electricity Statement of Opportunities, August 2018

Figure 17.7: AEMO Figure 4 of 2018 report – Forecast annual consumption (as sent out)

Figure 4 **Forecast annual operational consumption (sent out) with stacked components (Neutral scenario)**

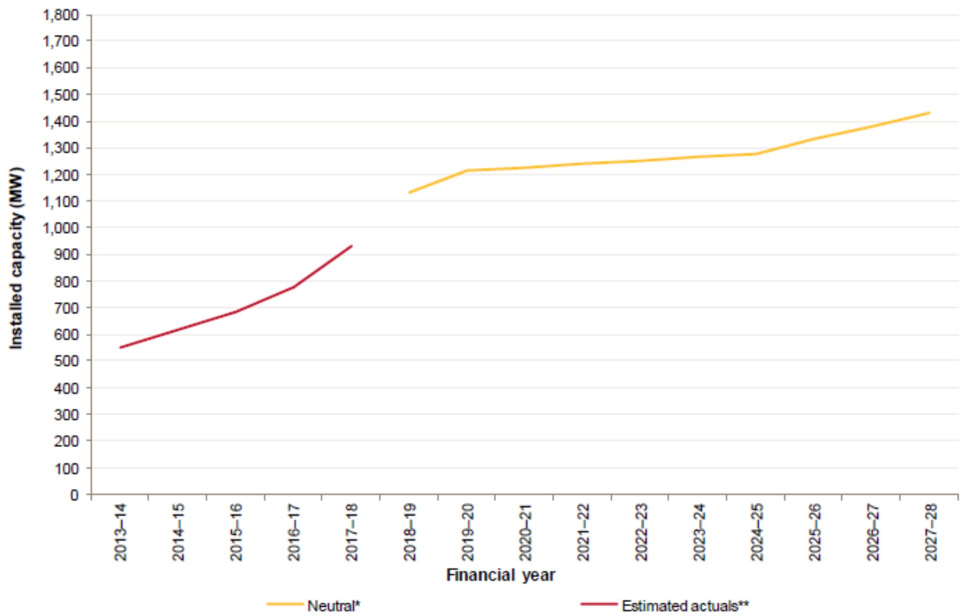


Source: AEMO South Australian Electricity Report 2018[12], Page 20

AEMO is forecasting a high take-up of solar through to 2020 (Figure 17.8), when forecast energy prices are expected to reduce. Solar take-up then flattens out through to the end of the 2020-25 RCP. SA Power Networks included this solar forecast into the 2020-25 RCP.

Figure 17.8: AEMO Figure 1 of 2018 report – Forecast Rooftop solar – Installed Capacity

Figure 1 **South Australian rooftop PV installed capacity forecasts**



* The 2018 ESOO maintained the same rooftop PV installed capacity forecasts across scenarios.
** After an improvement in the estimation for actual rooftop PV installation data, based on updated Clean Energy Regulator (CER) information and used during the production of the 2018 ESOO, installation data has changed from that reported in 2017 SAAF reports.

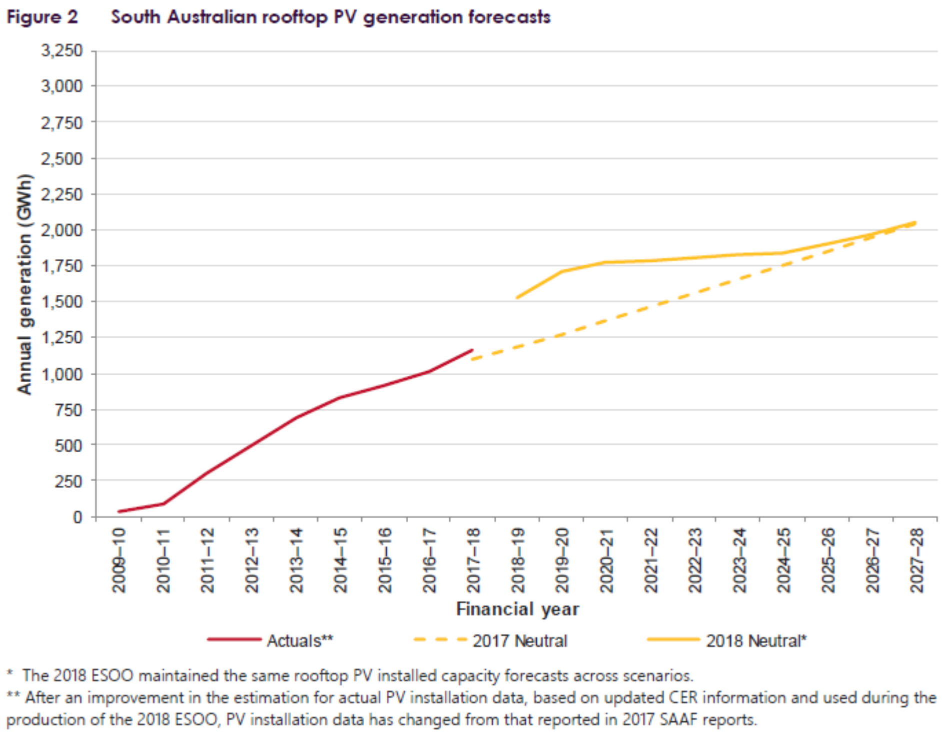
Source: AEMO South Australian Electricity Report 2018[Error! Bookmark not defined.], Page 15

AEMO states in their 2018 report on South Australia:

> '*Over the next 10 years, South Australia is projected to have the highest ratio of rooftop solar generation to operational consumption of all NEM regions. This is attributed to the state's high penetration of rooftop solar installations, good solar resources, and the second-lowest operational consumption of all regions in the NEM and Western Australia's Wholesale Electricity Market (WEM)*'.

In 2017-18, annual rooftop solar generation was estimated at 1,162 gigawatt hours (**GWh**). It is forecast to increase to 2,050 GWh by 2027-28. This represents approximately 15% of annual underlying consumption. Figure 17.9 (AEMO Figure 2) shows the actuals, and estimated forecasts of annual rooftop solar generation for South Australia from 2009-10 to 2027-28.

Figure 17.9: AEMO Figure 2 of 2018 report – Forecast annual consumption (as sent out)



Source: AEMO South Australian Electricity Report 2018 Error! Bookmark not defined., Page 16

SA Power Networks has incorporated this solar production forecast into the 2020-25 energy volumes forecast, after adjusting for that proportion of solar production used in-house, that exported to the network, and that sent to batteries for subsequent in-house use. Energy volumes are reduced by in-house use and are unaffected by exports to the network.

AEMO reports in their 2018 ESOO report for South Australia[12] that the continuing high growth in rooftop solar is reducing the operational demand forecasts and introducing times of negative demand forecast by 2023-24. 'Minimum demand continues to occur in the middle of the day in South Australia, with a minimum demand of 645.6 MW[13] recorded at 1:30 pm in 2017-18.' [14]

This was forecast earlier by an independent study conducted by the Commonwealth Scientific and Industrial Research Organisation (**CSIRO**) and Energy Networks Australia[15] where they state that the incidence of solar continues to grow. Analysis undertaken by them suggests that zone substations in South

[12] AEMO South Australian Electricity Report, November 2018

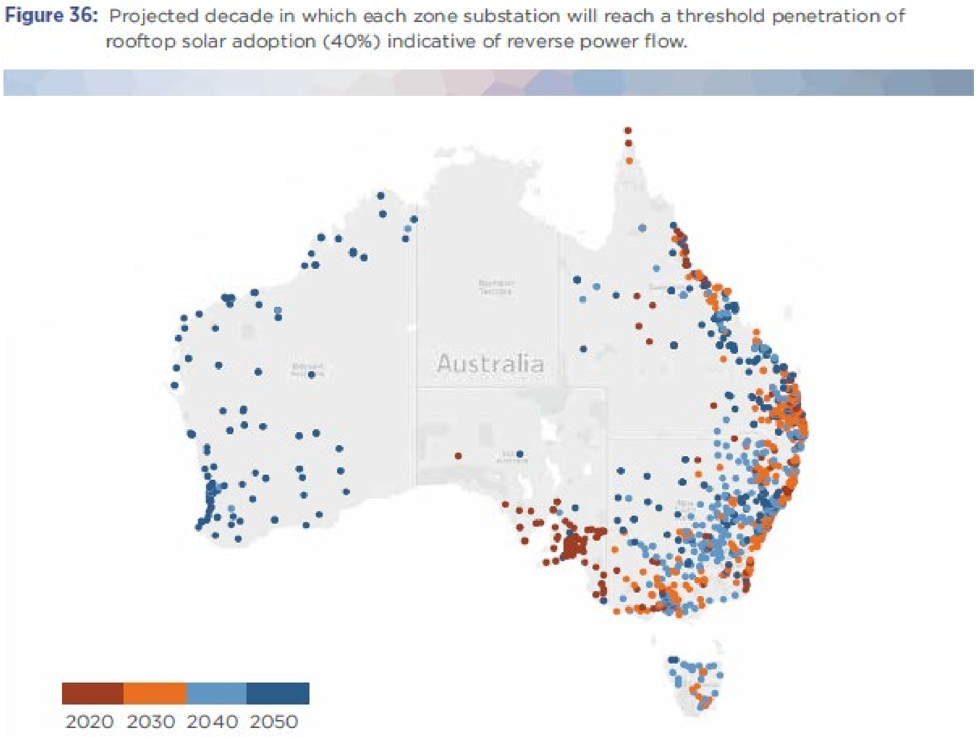
[13] This AEMO minimum includes unscheduled generation

[14] ibid, Page 4

[15] Electricity Network Transformation Roadmap: Final Report, April 2017

Australia have already met the threshold of reverse power flows or will do so by 2020. This demonstrates the effects on the network of the continued take up of rooftop solar by South Australian customers.

Figure 17.10: Projected decade when zone substation reaches a reverse flow condition



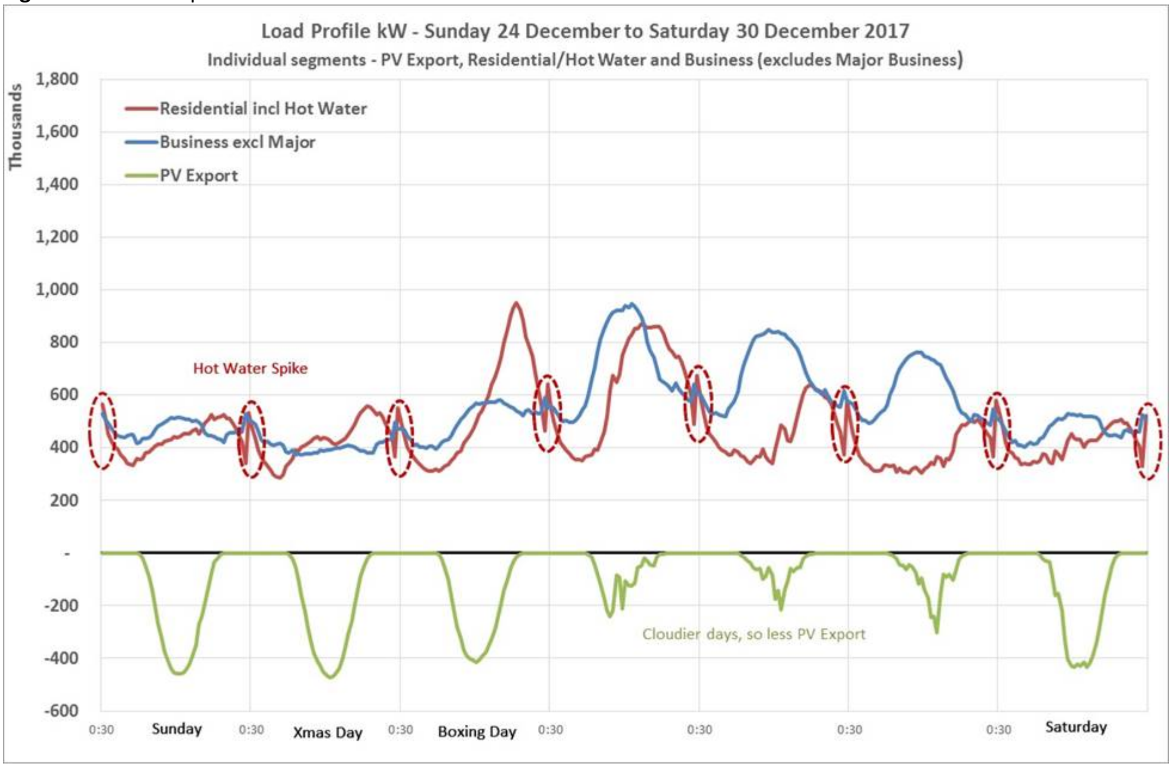
Source: Electricity Network Transformation Roadmap: Final Report April 2017[15]

17.3.7 Coincident demand

Figures 17.11 and 17.12 show various demand profiles for each customer segment at various times for the South Australian distribution network:

- The variability in solar export depending on solar irradiation and (on extreme days) the level of inhouse use.
- The variability from weather on residential load.
- The off-peak controlled load (**OPCL**), or hot water spike is apparent near midnight each night.
- The variability of business on work and non-work days and on extreme days.
- The diversity between the three profiles (solar export, residential and business).

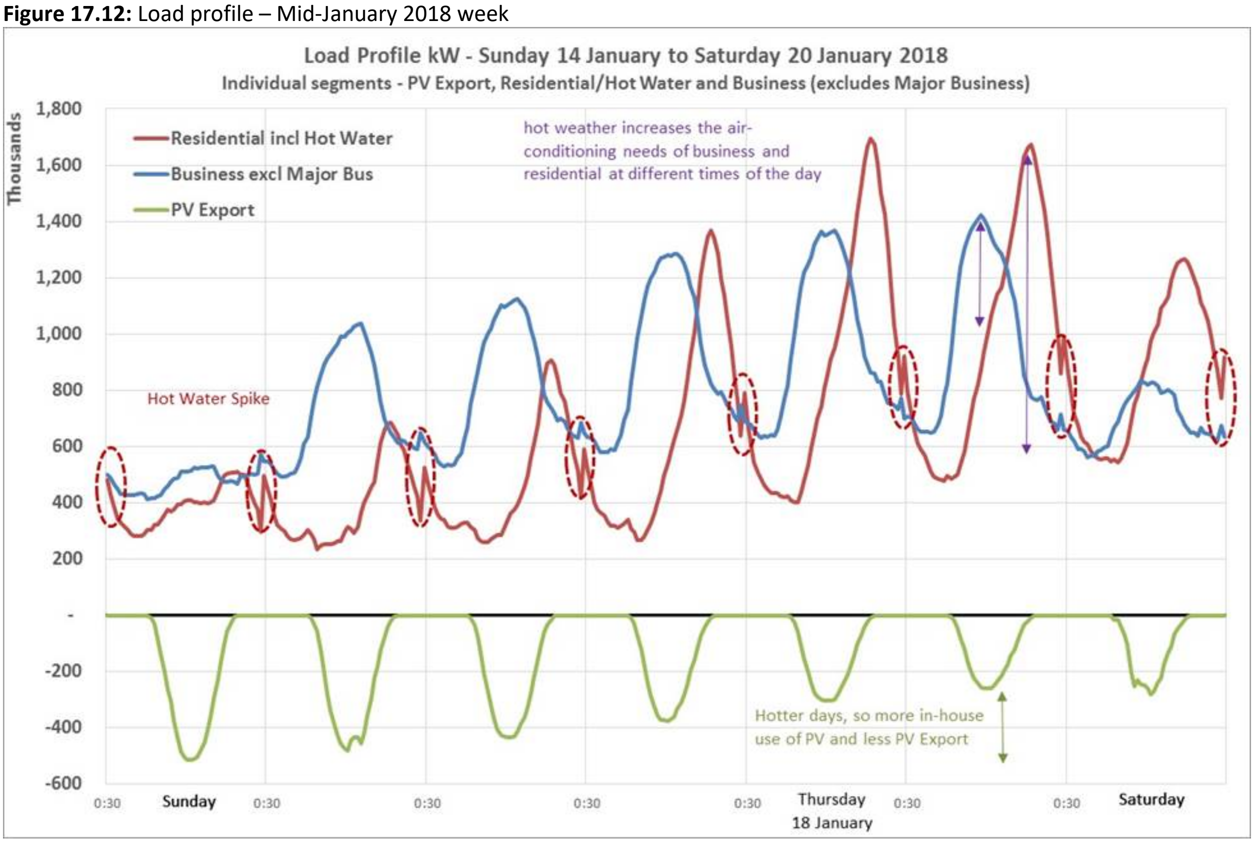
Figure 17.11: Load profile – Christmas week 2017



Source: SA Power Networks Analysis

Figure 17.11 shows the individual segment outcomes for a low demand period over the Christmas 2017 week. Export from solar is represented by the green line, the residential load (including hot water) by the red line, and the business (excluding major business) by the blue line. Figure 17.12 shows the outcomes for a high demand period in mid-January 2018, a few weeks later.

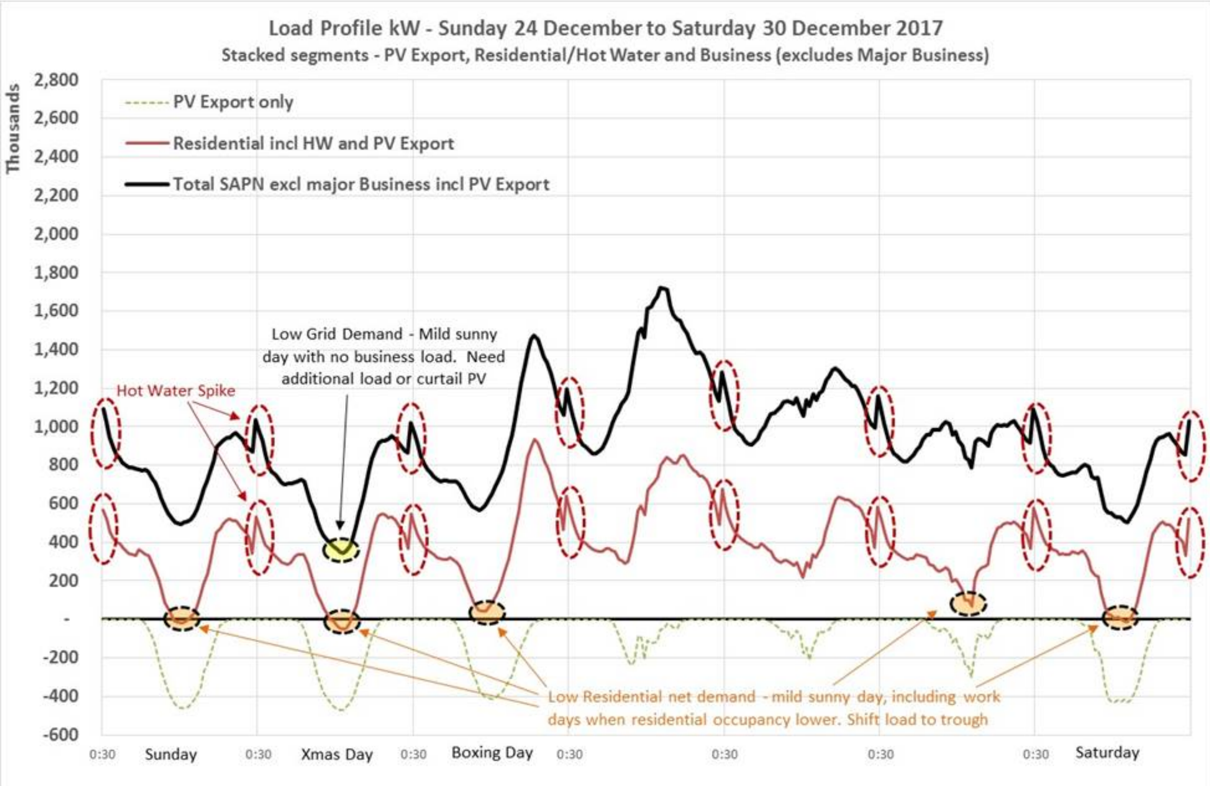
Figure 17.12: Load profile – Mid-January 2018 week



Source: SA Power Networks Analysis

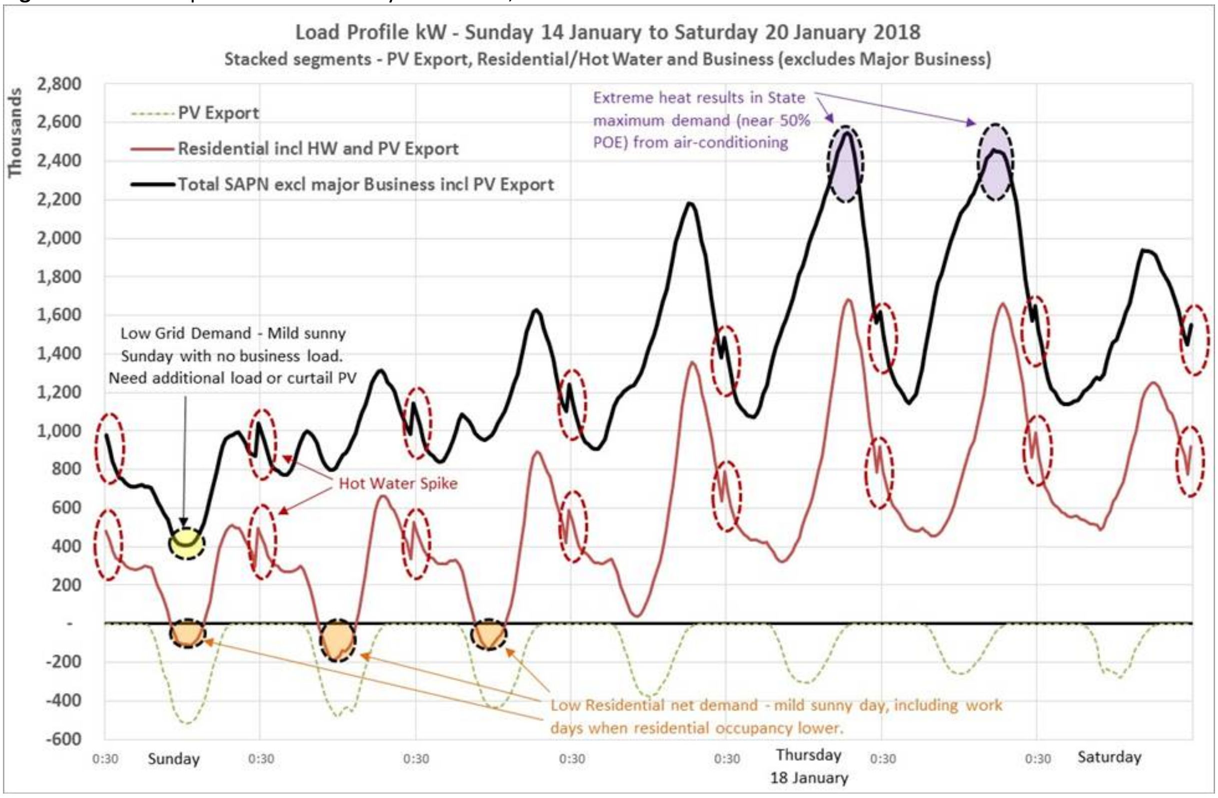
If we combine the solar export and the Residential Load, the likely net Residential network profile can be seen. Figures 17.13 and 17.14 show this as the red line for the low demand Christmas 2017 week and the high demand mid-January 2018 week. The negative load troughs can be seen, as well as the evening peak demands from air-conditioning on extreme days. Residential networks have significant volatility from high levels of solar and air-conditioning.

Figure 17.13: Load profile – Christmas week 2017, Residential Net loads



Source: SA Power Networks Analysis

Figure 17.14: Load profile – Mid-January 2018 week, Residential net loads



Source: SA Power Networks Analysis

If we combine all these profiles, the likely distribution network profile (solar, Residential and Business) can be seen (the black line in the charts above). The minimum load occurs on Christmas day, and the peak load in mid-January. The Hot water spike near midnight can also be seen. The contribution of 'Residential net of solar' load to coincident demand on the network is also apparent. The coincident peak occurs in the 5:00pm to 9:00pm window. The load characteristics discussed above underpin the development of our tariff structures and pricing signals for 2020-25.

17.3.8 Our forecasts

Our forecasts are summarised in the following tables and discussed in the appendices for:

- customer numbers
- energy volumes carried on our distribution network
- co-incident demand
- new technologies including solar and batteries

17.3.8.1 Customers

The forecast of our customer numbers is based on analysis supported by AEMO for residential customers and on our own data analysis for business customers. This is discussed in Appendix G at Section G.5, and summarised in Table 17.2.

Table 17.2: Forecasts of customer numbers (based on 2018 AEMO ESOO for residentials)

	Year ended 30 June							
	2018	2019	2020	2021	2022	2023	2024	2025
AEMO Residential	774,419	784,236	794,499	804,774	813,411	820,229	827,013	833,742
SAPN Small Business	92,759	93,037	93,316	93,596	93,877	94,159	94,441	94,724
SAPN Large LV Business	5,419	5,435	5,451	5,467	5,483	5,499	5,515	5,532
SAPN HV Business	224	225	226	227	228	229	230	231
SAPN Major Business	26	29	29	29	29	29	29	29
Metered active NMIs	**872,847**	**882,962**	**893,521**	**904,093**	**913,028**	**920,145**	**927,228**	**934,258**
Unmetered supply	4,001	4,040	4,079	4,119	4,160	4,200	4,241	4,282
No supply customers	17,548	17,719	17,892	18,067	18,243	18,421	18,601	18,783
All supplies active during the year	**894,396**	**904,721**	**915,492**	**926,279**	**935,430**	**942,766**	**950,070**	**957,323**

Source: SA Power Networks analysis supported by AEMO residential forecasts (note: Totals may not add due to rounding)

17.3.8.2 Our energy volumes

The forecast of the energy carried on our distribution network is based on analysis supported by AEMO forecasts for South Australia. This is discussed in Appendix G at Section G.4 and summarised below.

Table 17.3: SA Power Networks Volume Forecasts (GWh) by Tariff Class

	Year ended 30 June					
	2020	2021	2022	2023	2024	2025
Residential						
AEMO forecast	3,272	3,282	3,293	3,294	3,286	3,300
Adjustments [1]	206	157	167	179	196	218
SA Power Networks volume forecasts	**3,478**	**3,439**	**3,460**	**3,473**	**3,482**	**3,518**
comprises						
- *Residential*	*3,001*	*2,978*	*3,014*	*3,044*	*3,069*	*3,121*
- *OPCL (Hot Water)*	*477*	*461*	*445*	*429*	*413*	*397*
Business						
AEMO Forecasts	4,977	4,960	4,962	4,969	5,007	5,051
Adjustments [1]	189	191	194	196	199	201
SA Power Networks volume forecasts	**5,166**	**5,151**	**5,156**	**5,166**	**5,206**	**5,253**
comprises						
- *Unmetered*	*115*	*115*	*115*	*115*	*115*	*115*
- *Small business*	*1,385*	*1,381*	*1,383*	*1,385*	*1,396*	*1,409*
- *Large LV Business*	*2,879*	*2,871*	*2,874*	*2,879*	*2,902*	*2,929*
- *HV Business*	*786*	*784*	*784*	*786*	*792*	*799*
Major Business						
AEMO Industrial Forecast [3]	2,772	2,801	3,195	3,203	3,236	3,273
Difference [2]	(1,723)	(1,752)	(2,146)	(2,154)	(2,187)	(2,224)
SA Power Networks volume forecasts	**1,049**	**1,049**	**1,049**	**1,049**	**1,049**	**1,049**
comprises						
- *Zone substation*	*495*	*495*	*495*	*495*	*495*	*495*
- *Sub-Transmission*	*554*	*554*	*554*	*554*	*554*	*554*
Total SA Power Networks volume forecasts	**9,693**	**9,639**	**9,664**	**9,687**	**9,737**	**9,819**

Source: AEMO forecasts

Note: Totals may not add due to rounding

1. Adjustments : for calibration, PV and battery export
2. Difference (Major Bus) : ElectraNet customers, less some Business customers SAPN classifies Major
3. AEMO Industrial Forecast : this includes some ElectraNet-connected customers eg Roxby, pipelines

17.3.8.3 Our Co-Incident Demand, Global vs Spatial reconciliation

SA Power Networks forecast Co-incident demand is discussed in Appendix F at Section F.2.4 and Appendix G at Section G.7.

A summary of the demand forecasts for SA Power Network customers is summarised below:

Table 17.4: Forecasts of co-incident demand (AEMO and SA Power Networks)

Year ended 30 June	2018	2019	2020	2021	2022	2023	2024	2025
SA Actual Peak MW								
SA 10% POE Forecast (AEMO)	3,147	3,195	3,189	3,203	3,278	3,249	3,286	3,314
SA 50% POE Forecast (AEMO)	2,866	2,918	2,911	2,918	2,974	2,975	3,000	3,022
SA Power Networks Actual Peak MW	2,630							
SA Power Networks 10% POE Forecast (Co-Incident Transmission Exits)		2,886	2,899	2,913	2,921	2,929	2,937	2,945
SA Power Networks 50% POE Forecast (Co-Incident Transmission Exits)		2,620	2,632	2,646	2,654	2,662	2,670	2,678
Difference SA (AEMO) and SA Power Networks Actual Peak								
Difference SA (AEMO) and SA Power Networks 10% POE Forecast		309	290	291	357	321	349	369
Difference SA (AEMO) and SA Power Networks 50% POE Forecast		299	279	272	320	313	330	344

Source: SA Power Networks analysis of AEMO and other data

17.3.8.4 New Technologies – Solar and Batteries

Table 17.5: AEMO Forecasts for solar and battery installation (CSIRO Moderate Case)

	Year ended 30 June					
	2020	2021	2022	2023	2024	2025
Solar Effective capacity (MW)						
Residential	982.7	991.0	999.4	1,008.1	1,022.8	1,034.2
Business	266.0	270.8	275.8	281.0	286.4	291.9
Total Customer solar	1,248.7	1,261.7	1,275.2	1,289.1	1,309.1	1,326.1
Non-Scheduled Generation	68.3	79.3	105.1	129.2	152.4	175.6
Total solar MW	1,317.0	1,341.0	1,380.3	1,418.3	1,461.5	1,501.7
Battery Effective Capacity (MW)						
Residential	82.5	165.8	166.6	167.5	168.3	169.1
Business	3.4	3.7	3.9	4.2	4.7	5.3
Total Battery MW	85.9	169.5	170.5	171.7	173.0	174.4
Battery Effective Capacity (MWh)						
Residential	214.5	431.1	433.2	435.4	437.6	439.8
Business	8.8	9.5	10.1	11.0	12.3	13.7
Total Battery MWh	223.3	440.6	443.3	446.4	449.9	453.4

Source: AEMO forecasts

Note: Rounding may affect the presentation of totals

17.4 The key challenges we are trying to address

17.4.1 Changing impacts on our customer

Our tariffs need to respond to the changing impacts on our customers in order to be able to respond to their needs and offer appropriate pricing signals to influence the demands today and the expected demands of the future.

Appendix F sets out the changes that we have observed and the changes that we forecast to impact our customers in the future. These changes include small scale solar, batteries, electric vehicles and their impacts on underlying demand and energy volumes.

17.4.2 The residential daily profile has moved our peak

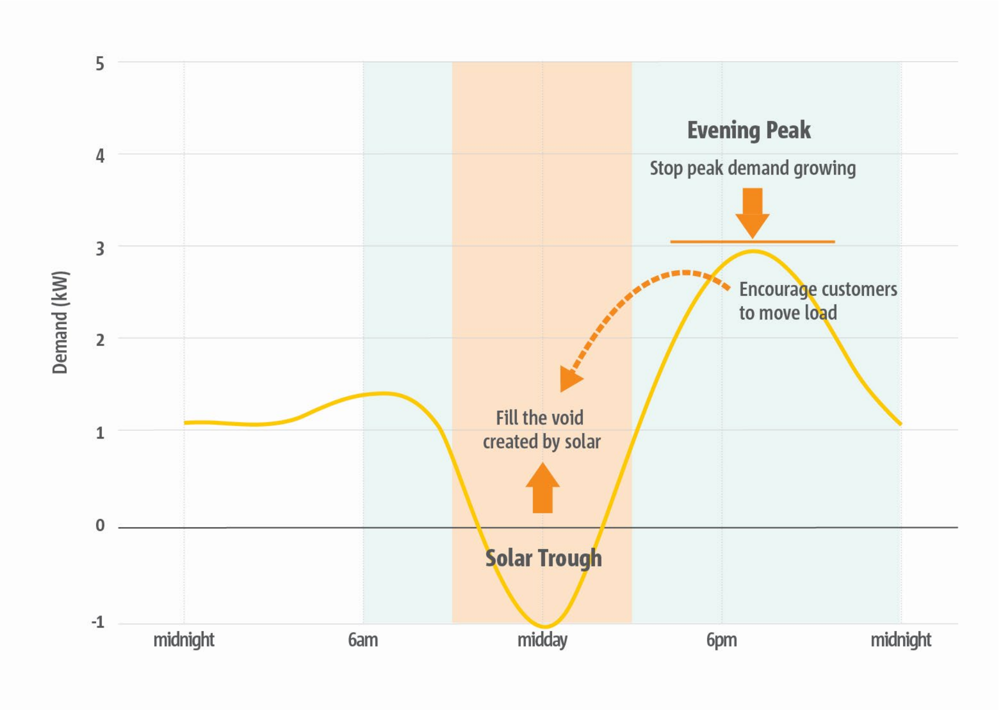
Until recently, ever-increasing customer demand required us to build more network capacity, primarily to meet increased residential air-conditioning loads on relatively few very hot summer days. The highest demand for electricity from our network was recorded back in 2009. Since then, overall net system demand has remained relatively flat or declined slightly, largely due to the amount of rooftop solar systems now connected to our network and the impact of energy efficient appliances.

The high solar penetration we are now experiencing results in high energy exports during mild sunny days and this is creating some limitation for further increases in exports and increases the potential for degradation of power quality.

More detailed analysis on our peak demand is included in Appendix C below. This analysis includes timing and locational issues which shows how the peak differs between parts of the network and times of the day. This excess generation is creating a demand void or ‘solar trough’ on our network particularly in the middle of mild sunny days, while we must still manage the demand peaks a few hours later in the evenings. Without more cost-reflective pricing, and other mechanisms we will need to increase network capacity to cater for the localised coincident peak of extra solar generation during the ‘solar trough’, rather than the air-conditioning demands of the past.

Figure **17.15** demonstrates the impact of the demands we are responding to.

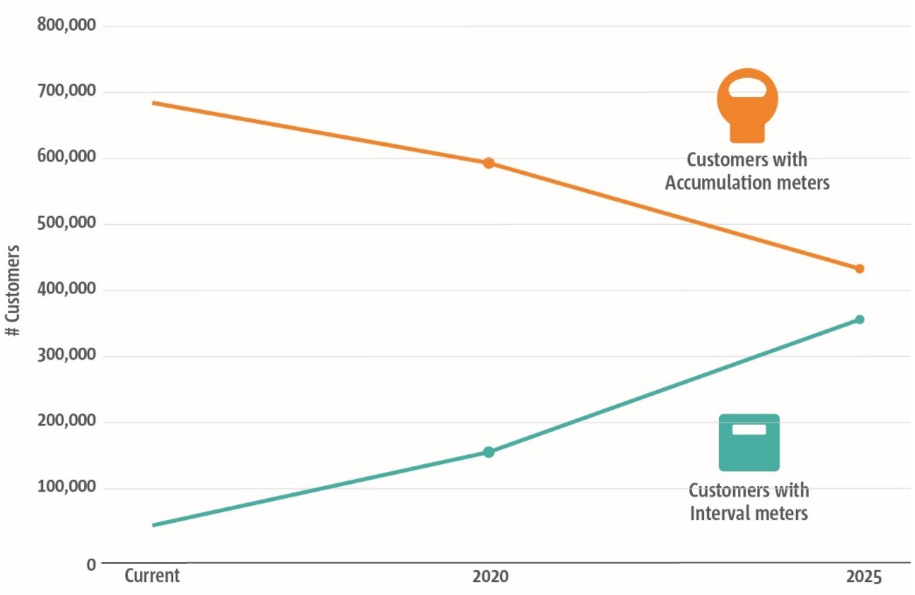
Figure 17.15: Network peak load curve for a day



More cost-reflective tariff structures can help address this trend, but they are dependent on the type of metering that customers have at their premises. 'ToU' tariff structures are proposed for residential and small business customers who have Type 4 or Type 5 interval meters to provide better pricing signals that encourage desired usage behaviours.

Only 13% of residential customers and 15% of business customers currently connected to our network are supplied through interval meters, but we expect this to move to 45% by 2025 (see Figure 17.16). All new and replacement meters must now be Type 4 meters under the metering contestability rule changes that applied from December 2017.

Figure 17.16: Change in the population of metered residential customers



Source: SA Power Networks Analysis

More cost-reflective tariffs (on average) give customers a lower average price and provide opportunities for customers with flexible loads to shift some of their energy use to lower-priced periods.

Moving loads like pool pumps, washing machines, clothes dryers and hot water heating to lower price periods can help customers manage the cost of electricity. In the future, these times would also be ideal to charge electric vehicles and batteries.

Our tariff structures are designed to empower customers to make informed choices by:

- ***providing better price signals*** — our tariffs reflect what it costs to use electricity at different times of the day so that customers can make informed decisions to better manage their bills. Where customers have flexible loads (including batteries, electric vehicles and hot water storage heating) they may move the timing of those loads to a lower price time available every day;
- ***transitioning to greater cost reflectivity*** — we will give customers (and their retailer) a choice on the speed to which they will see the transition to cost-reflectivity; and
- ***managing future expectations*** — we will continue to guide retailers, customers and suppliers about services such as local generation, batteries, and demand management by setting out our tariff approaches for the 2020–2025 regulatory period.

To respond to the change in the residential daily profile, we propose to introduce a 'solar sponge' component offering a super cheap off-peak charge within the ToU tariff for the time when solar exports are high. This does require an interval meter to enable this charge to take effect.

We are also proposing incentives and time clock adjustments to shift some hot water away from the 11:00pm spike in demand and into the solar sponge. This is more of a residential issue than a business issue.

17.4.3 Peak Demand

The time of the peak demand has moved from mid-afternoon to early evening in response to the outport from solar. This applies to all of South Australia except the Adelaide CBD area.

The response to this peak demand will be managed in a number of ways as outlined below.

- Residential – Replacement of older air-conditioning plant with more efficient equipment over the coming years will decrease peak demand. No tariff signal is required for this. Any savings will be reflected in lower prices through the cost allocation process through lower diversified demand.

- Residential – The introduction of a Prosumer tariff, aimed at customers with batteries in particular will provide incentives to shift load out of the peak period. Battery discharges during peak summer windows will provide a lower price (avoiding peak usage and lower demand charge). The demand window is 5:00pm to 9:00pm November to March.

- Small business – The ToU usage tariff proposed for customers with interval meters will result in a peak price 1.5 times the single rate and apply to the 5:00pm to 9:00pm November to March period. Customers with a flexible load at this time may shift this load to other times either completely or partially in response. It may be that weekend irrigation for example avoids this time period (previously an off-peak window). And that nightly irrigation starts are delayed to a later period. Other businesses with flexible load may also avoid this 5:00pm to 9:00pm window.

- Large business (non-CBD) – The agreed peak demand window moves from a half hour on 12:00pm to 9:00pm work days November to March to a four-hour average 5:00pm to 9:00pm any day November to March. There is an annual charging option, and for seasonal customers operating in only some of these months, a monthly charging option. Customers can reduce their charge by avoiding some or all of this period regularly, or by using other energy sources eg solar and or a battery.

- Large business (in the CBD) – The charges and outcomes for CBD Large business are generally the same as non-CBD Large business except that the window for the peak occurs for a six-hour period from 11:00am to 5:00pm work days November to March recognising the CBD peak profile. Customers could self-supply on extreme days or install more efficient equipment.

17.4.4 Emerging issues

In addition to the changes we have outlined above, there are other emerging issues which we will have to respond to in the medium term.

- Electric vehicles – EV recharging is forecast by AEMO to become an issue with residential customers in 2025-30 with a possible peak demand increment of 80MW depending on customers' choice of recharging times.

  Our residential ToU and Prosumer tariffs provide opportunity for lower-priced recharging at home for those with interval meters away from the coincident peak. (We already allow recharging of electric vehicles on OPCL, which provides an opportunity for low-cost recharging for Residential customers using Type 6 meters fitted with OPCL capability.)

  Commercial electric vehicle recharging stations are treated as a business. The proposed network pricing proposals should promote efficient development of such facilities more so than current pricing arrangements.
  - Sites needing less than 70 kVA will have a ToU price. These are likely to be small kerbside facilities with diversity to the neighbourhood.
  - Sites needing more than 70 kVA but using less than 160MWh pa will have an anytime demand charge for the maximum demand ensuring the site pays incremental costs. A ToU charge applies to usage.
  - Large commercial sites needing more than 70kVA and using more than 160 MWh pa will also have a peak demand charge with lower ToU rates:
  - In the CBD, the peak demand is measured as an average of the 6-hour period 11:00am to 5:00pm November to March, so is not determined by an individual half hour; and
  - In the rest of South Australia (non-CBD), the peak demand is measured as the average of the 4-hour period 5:00pm to 9:00pm November to March.

  These arrangements should give greater flexibility and opportunity for commercial electric vehicle recharge facilities to have a lower network charge through load management whilst enabling the existing network capacity to supply this new load.

- Virtual Power Plants (**VPPs**) - There is no tariff response proposed for VPPs as yet, but we are considering the best option to manage the incentives/response to these new innovations. We will consider options which may result in a tariff trial of a VPP in 2020-25. Options include:
  - pricing each customer in a VPP individually (status quo);
  - pricing all the customers in a VPP connected to the same distribution transformer as a single entity (ie pricing the Financially Responsible Market participant (**FRMP**) rather than pricing the customer); or
  - some other arrangement.

  The aim is to provide economically efficient behaviour incentives to the VPP operator whilst retaining equity amongst all residential customers. This is an issue to be resolved over 2020-25.

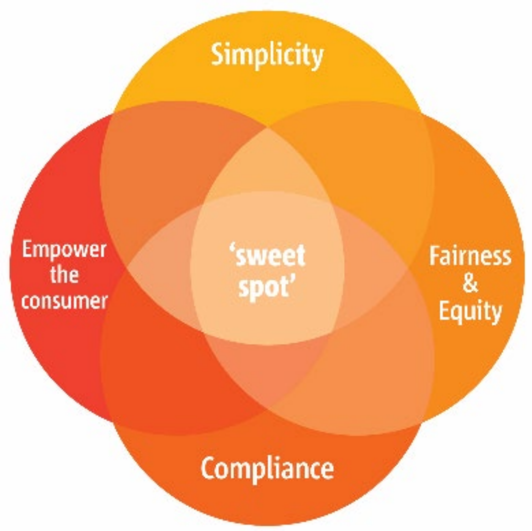
17.5 Customer impact principles

When developing our initial 2017-2020 TSS, we conducted a deliberative process in 2016 with a representative customer group. As a result of this process a series of principles were developed to guide decision-making around future tariff structures. These principles are defined as:

- **Principle 1** — empower the consumer
- **Principle 2** — fairness and equity
- **Principle 3** — simplicity (to inform decision making)
- **Underlying principle** — compliance

We continued to apply these principles as we developed our tariff proposals for the 2020-25 RCP as set out in this proposed TSS.

Figure 17.17: Customer impact principles



17.6 AER directions

When the AER approved our 2017-2020 TSS, the AER indicated it expected to see the pace of transition increase over the 2020-25 period. In particular they wanted to see:

- pricing, network planning and demand management interaction;
- a lift in the pace of tariff reform and customer assignment to cost-reflective tariffs (such as moving away from opt-in tariffs to opt-out tariffs if suitable metering is available);
- improved quality of long run marginal cost estimates;
- a reconsideration of the use of a 30-minute window to measure demand; and
- more refined pricing windows and methods for determining the charging window time.

In addition, the AER has been asking distribution businesses to advise them of:

- the consultation process undertaken to develop pricing proposals, and how we made the distinction between consultation with customers, customer representatives, retailers and State Government;
- the effect of emerging technologies and market changes that will impact the network by 2025 and how our proposals consider these changes; and
- how we balance simplicity and affordability with cost-reflectivity in these tariff structures.

In response to this:

- the engagement process is discussed in Section 17.8 and the Customer and stakeholder engagement report;
- the effect of emerging technologies is discussed in Section 17.4 and how we have responded is outlined in Appendix C; and
- our response to balancing simplicity and affordability with cost reflectivity is set out in Section 17.14.

17.7 Types of tariffs and tariff redesign strategies

With the evolution of the customer and their adoption of new energy technologies, the use of the network has changed. We have redesigned our tariff strategies to better align with this change. We have done that with reference to the pricing principles in the NEM particularly:

- Looking at the incremental cost of a customer to ensure that all customers are at least paying incremental cost.
- Limiting the potential for tariffs to exceed the stand alone cost of supply, so removing incentives for inefficient bypass. Bypass may still occur, but it shouldn't be inefficient network bypass if our pricing is right (it may occur due to energy prices or customer specific preferences).

17.7.1 Local connection assets

We are increasing the small customer supply charges by:

- $10 pa for residential; and
- $20 pa for small business.

As a result, a greater proportion of the customer-related costs, the service wire and the low voltage wires are recovered on a per-customer basis. We believe this is more cost-reflective and results in lower usage charges. We believe that this improves the cost reflectivity of smaller and medium-sized customers and is more equitable between customers with and without DER such as solar.

We are amending the existing demand charges that were applied for peak demand with an increment for anytime additional demand into discrete charges for 'peak demand' and for 'anytime demand' (eg if the existing price was for peak demand of $100 and anytime additional demand of $40, the new prices are for peak of $60 and an anytime demand, applicable to all demand, of $40). The outcome is the same, but the anytime charge more clearly reflects the charge for the connection. We determine the anytime charge on the customer's anytime demand (maximum 30-minute interval for the last 12 months, unless an agreed amount applies).

We are applying the anytime demand charge to all large businesses and to those small businesses with actual demand greater than 70 kVA. Following extensive engagement, we are not requiring an anytime demand charge for residential customers or for small business customers less than 70kVA.

17.7.2 Peak demand

In relation to peak demand:

- We determine the peak demand amount based on the customer's contribution to coincident peak measured by the demand across the peak demand window in summer (ie an average demand measured across the daily peak demand window).
- We are applying the peak demand charge to all large businesses.
- Residential Prosumers can opt-in to a tariff with a peak demand charge.
- Small business customers will face a higher ToU charge during the peak demand window.

17.7.3 Residual costs

We continue to recover the residual costs through usage charges. For large business, the recovery from peak demand charges in 2020-25 will be less than 2015-20 because the demand measurement window moves to 5:00pm to 9:00pm from the current period of 12:00pm to 9:00pm. As business has lower demand in this later window (5:00pm to 9:00pm), less of the business network costs will be recovered by demand. We propose to use a peak usage charge to recover the shortfall. We propose to retain the current lower usage price for off-peak times.

17.8 Customer engagement

Our customer engagement process is discussed in more detail in the Customer and stakeholder engagement report. The key feedback we obtained in respect to tariffs is presented below. Our tariff workshops and bilateral meetings with customers and stakeholders included presentation and discussion of key aspects of our tariff development plans.

We undertook a multi-stage engagement process specifically on tariffs from November 2017 to January 2019. This engagement process was designed to:

- ***build an understanding*** of the current challenges, context and obligations in relation to tariff setting;
- ***explore allocation preferences*** between residential and business customers; and
- ***explore customer impacts and gather feedback*** on residential, small business and large business tariff proposals.

We have consulted with customers and stakeholders from:

- our standing reference groups including:
  - Arborist
  - Business
  - Community
  - Renewables
  - Customer Consultative Panel
- South Australian Government
- Energy Consumers Australia
- Australian Energy Market Commission
- Australian Energy Market Operator
- Australian Energy Regulator
- AER Consumer Challenge Panel (**CCP14**)
- Energy Networks Australia and other distribution businesses
- Retailers:
  - Australian Energy Council
  - Alinta Energy
  - AGL
  - Lumo Energy
  - Origin Energy
  - Simply Energy
  - Energy Australia

This engagement has occurred via reference group discussions, bilateral meetings, and a dedicated tariff deep dive workshop[16] (see Figure 17.18), which brought together the diverse views of different stakeholder cohorts (see Table 17.6).

Figure 17.18: Tariff Structure Statement engagement

The following table represents a summary of the feedback from our consultation process.

Table 17.6: Customer and stakeholder feedback and our response

What we heard	Our response in this TSS
"Business shouldn't have to bear the costs for services not provided to them."	• Guaranteed Service Level (**GSL**) costs shifted from being recovered across all usage, to small customers (residential and small business) only, on a per customer basis
"The proposed tariff structures are very complex. Simplicity please."	• Reduced the number of tariff elements from initial proposals • Reduced the number of tariffs proposed from initial engagement with stakeholders • Simplified 'anytime blocks' to only address critical issues • Ensured consistency between time blocks where possible
"The Critical Peak Pricing tariff is too complex."	• No longer proposing the Critical Peak Pricing tariff
"Tariffs should be designed with retailers in mind." Retailers asked to be informed of the most important tariff elements.	• We will continue to engage with retailers on tariff design • We have not referred to likely NEM pricing, but have looked at the congestion in our network when determining the new tariffs • We have reduced the off-peak residential ToU to those periods best suited to address daily network issues • We will confirm with retailers the critical components of our tariffs
"Customers need 12 months of data to understand their usage before moving to a new tariff."	• We expect retailers will offer tariff choices • If retailers don't offer a choice of tariffs, the network price impact on small customers should not be significant and we feel doesn't warrant the provision of data
"Stage the transition through pricing within tariff structures."	• We will transition all small customers to a new structure evenly over a five-year period
"How will desired behaviour changes result in outcomes and how will these impact future planning?"	• Largely the customer response is unknown at this stage, but we expect that daily and summer congestion will reduce or at least not increase, which should result in lower future capex from avoiding or deferring augmentation and expansion of the network • We will continue to work collaboratively to ensure network planning and tariff structures are complementary
"Moving to greater fixed costs removes any incentive or possibility for customers to modify behaviour to reduce costs."	• We acknowledge concerns raised about fixed supply charges but believe there is still sufficient variable charge to encourage customers to respond

[16] *Supporting Document 0.10 - AnnShawRungie Tariffs Deep Dive Workshop Report*

"Fixed charges are regressive and do not encourage energy conservation."	• We believe our plans to slightly increase supply charges are more cost-reflective and remove some cross-subsidy • Our plans align with a world-wide trend to increase the fixed charged component
"An appropriate recovery of revenue for the next regulatory period would be roughly 1/3 each for fixed, variable and demand charges."	• We propose to limit any supply charge increase to $10 per annum. Supply charges will recover approximately 25% of our overall costs by 2025, heading towards, but well within, the one third suggested in consultation
"What about the impact on non-solar customers, who are continuing to pay more for network charges as solar penetration in SA increases?"	• We propose to retain the pricing relativity between single-rate, ToU rates and Prosumer tariff rates – this means Type-6 meter customers won't be unfairly impacted by other customers installing solar • Any revenue shortfalls from customers responding to ToU signals will result in equal price increases to all residential tariffs • Our proposed ToU and Prosumer residential tariffs will reward customers for 'soaking-up' surplus solar energy in the middle of the day • Early modelling of customer impacts indicates that non-solar customers are better off under the default ToU tariff • By enabling more lower cost renewables to be connected to the network, the entire community will benefit from downward pressure on wholesale electricity prices and cleaner energy solutions
"Managing the 'solar trough' is important."	• The new tariffs proposed are aimed at managing residential congestion associated with solar through and the hot water spike, plus Prosumer signals for extreme summer days
Customer Impact Principles are supported	• The off-peak and 'solar trough' periods provide year-round options for residential customers to shift load and pay a lower price • Fairness and impacts of solar and non-solar customers addressed through the proposed ToU tariffs • Customer with solar will get benefits from in-house use • The ToU tariff is the default for interval meters, the Prosumer tariff is opt-in • The ToU tariff should relieve some 'solar trough' and hot water congestion
"We encourage SA Power Networks to trial more innovative tariffs before 2025."	• We propose a suite of trials including: o Riverland tariff trial retained for 2019-20 o A range of measures to address hot water being considered o Residential ToU trial proposed for 2019-20 with Type 4 meters only (needs retailer support)
"We want confidence that tariffs are being considered as a potential solution to network problems, along with demand management and other non-network initiatives"	• Our proposed tariffs are complementary to our Future Network Strategy, by encouraging customers to shift load away from the morning and afternoon peaks to soak-up surplus solar energy in the middle of the day, therefore deferring or avoiding network investment to cope with excess solar energy. • Our planned hot water demand management project and hot water tariff trial are complementary.
"Manage the impact of new cost-reflective tariffs on small businesses and some large businesses who are currently paying less, and will be paying more under new tariff structures."	• To avoid price shock, transition arrangements will be applied to limit annual price increases to $10/MWh for most small and large businesses, as they progressively adopt proposed tariffs according to their circumstances.

We will continue to engage with our customers and stakeholders on our tariff trials and tariff development, including opportunities for collaboration and community education.

For more information on TSS engagement please see the <u>Customer and stakeholder engagement report</u>.

17.9 Tariff classes

Part of the process of tariff design is to identify different tariff classes in order to consider tariffs that might apply to the customers in each class.

Tariff classes are defined by various attributes such as supply voltage, annual consumption and customer type.

We do not differentiate between customers with or without DER, nor on the type of meter installed. The type of meter does impact on which tariff can be used within the tariff class.

We have retained the tariff classes used in the 2017-20 TSS. They are:

- Residential
- Small business, business customers using less than 160 MWh pa, as per SA legislative definitions
- Large business LV, connected to the low voltage network but using more than 160 MWh pa
- Large business HV, connected to the 11kV high voltage system
- Major business, customers that require at least 5,000 kVA capacity and are connected to either the 11kV bus at a zone substation or the sub-transmission system (33kV or 66kV)

17.10 How we develop the tariffs for the 2020-25 Regulatory Control Period

In this subsection we have set out how we have developed a proposed tariff structure for the 2020-25 RCP for the five tariff classes:

- Residential
- Small business
- Large business - low voltage
- Large business - high voltage
- Large business - major business

17.10.1 Background to changes in the tariffs

By number the largest customer groups are the residential and small business classes. The residential customers within this group have particular peak loads influenced by the increasing effects of solar, along with a significant population of older accumulation meters (Type 6), which provides some challenges to the development of cost-reflective tariffs. However, the changes in metering that are likely to occur with the introduction of the 'Power of Choice' mean that the population of meters will change during the 2020-25 RCP.

Factors we need to respond to

There are a number of factors that we need to respond to in the development of tariffs for the residential and small business classes for the 2020-25 RCP. These include:

- Changes we are facing in the use of energy by our customers (Section 17.4)
- Technology that is available to measure customer usage (Section 17.4.2)
- Our customer impact principles (Section 17.5)
- The need to continue tariff reform as required by the AER (Section 17.6)
- Feedback from engagement with our customers (Section 17.8 and the Customer and stakeholder engagement report)
- Analysis of the work day and non-work day differences across tariff classes and locations discussed in Appendix C

We have responded to the factors outlined above and developed a proposed tariff structure which is simple, more cost-reflective and easy to understand. It also empowers the customer to make choices and change the way they use power when they can.

The proposed tariffs set out in this subsection will be applied to the following classes of customer (residential and business) depending on the metering technology available to them.

- Customers with Type 6 – an accumulation meter, read by SA Power Networks (typically quarterly).
- Customers with Type 5 – an interval meter, read by SA Power Networks (typically quarterly).
- Customers with Type 4 – an interval meter, read remotely by the retailer's meter data agent.

Some limitations, and solutions

Whilst the tariff reforms apply to all customers, there are limitations in the tariffs available to some customers due to their metering. Many customers still have Type 6 accumulation meters which are not suited to recent tariff innovation. The customer can request their retailer to change the meter to a new Type 4 meter and access alternative proposed tariff structures set out in this statement if they choose to do so. So, the tariff reforms are not exclusive and are effectively available to all customers at their request.

17.10.2 The proposed tariff structures for the Residential Tariff Class

There is no significant change to the majority of residential customers, and in response to customer feedback, the proposed tariff structures have been simplified to improve cost reflectivity and for ease of understanding (Table 17.7). The changes proposed:

- reduce the number of significant figures in prices to four (for example 12.75 cents per kWh); and
- eliminate the inclining block tariffs within the residential class, so that there is either a flat rate for anytime use, or a shoulder-rate and an off-peak rate for a ToU tariff.

Table 17.7: Residential tariffs proposed

Residential tariff	Tariff structure	Metering	Key features and considerations
Residential – Single rate	Supply charge + flat usage rate	Accumulation meter (Type 6)	• Supply charge will increase <$10 per annum • Single rate reverts to a single block from July 2019 • Only option for a residential customer with Type 6 metering • Companion tariff available for controlled load (hot water) for customers with existing off-peak controlled load metering
Residential – ToU	Supply charge + peak and off-peak usage rates	Interval meter, either: - remotely read (Type 4) or - manually read (Type 5)	• Default mandatory tariff for 2020-25 for residential customers with Type 4 or Type 5 metering. Same supply charge as single-rate • Companion tariff available for controlled load (hot water). Customers may access lower network prices by managing the ToU of such appliances • Two, five-hour off-peak blocks every day: - 1:00am to 6:00am (early morning) at 50% of the single rate price; and - 10:00am to 3:00pm (when solar export is at its highest) at 25% of the single rate price. • Price for the other 14 hours will be approximately 125% of the single-rate usage price
Residential – Prosumer	Supply charge + ToU + average summer peak demand charge	Remotely read interval meter (Type 4)	• New opt-in tariff for 2020-25 for residential customers with Type 4 metering. May suit customers with new technologies such as solar, batteries, electric vehicles and home energy management systems and households with less energy-intensive air-conditioning needs such as evaporative air-conditioning. • The tariff has the same supply charge as single-rate. • A companion tariff is available for controlled load (hot water). Customers may access lower network prices by managing the ToU of such appliances • The tariff will comprise: - supply charge — 25% of the average residential bill; - usage charges — 37.5%, split into a peak and off-peak usage; and - peak average demand charges in summer — 37.5%.

			• Prices for peak and off-peak usage will be proportional to the ToU, but at a lower level because of the demand charge. • Summer demand measured each month, November through March at the highest daily average level over the four-hour period, 5:00pm to 9:00pm, for that month. Designed to encourage battery owners to discharge at this time on hot days to offset their in-house use (air-conditioning in particular) and allow customers to use appliances as necessary during the four-hour period. During our engagement program we presented a Critical Peak Pricing (CPP) option for discussion but customers, advocates and retailers felt that this failed to deliver on the simplicity objective, so we are only proposing the simpler ToU and the less complex prosumer tariffs as cost-reflective tariffs.

The OPCL tariff will remain as there are still a significant number of these installations in service. This will change in time with more customers moving to ToU and as there are changes in 'controlled load' type appliances (eg replacement with more energy efficient appliances). Refer to section 17.10.3 for discussion on this class.

The rise of the 'Prosumer' introduces a new tariff for the residential class and recognises the change in our customer base where we now have customers who both produce and consume energy through our network. With more than 30% of our residential customers with solar on their roof, we need to have a network that can manage the flow of energy both ways. This represents a challenge to us and to the principles of equitable sharing of costs of the network.

The Residential customer tariffs are set out in Table 17.8. The prices are indicative, and include transmission and PV FiT recovery as well as distribution (referred to as Network Use of System (**NUoS)**)

Table 17.8: Residential tariffs 2020-21 NUoS Forecast

			$pa	$/kW pa	c/kWh			
Residential tariff	**Tariff structure**	**Metering**	**Supply charge**	**Peak demand charge**	**Peak usage charge**	**Off-peak usage charge**	**Solar sponge usage charge**	**Usage charge**
Residential – Single rate	Supply charge + flat usage rate	Accumulation meter (Type 6)	166	-	-	-	-	14.4
Residential – ToU	Supply charge + peak, an off-peak and solar sponge usage rates	Interval meter, either: - remotely read (Type 4); or - manually read (Type 5).	166	-	18.0	7.2	3.6	-
Residential – Prosumer	Supply charge + ToU + average summer peak demand monthly charge	Remotely read interval meter (Type 4)	166	* 110	10.2	4.1	2.0	-

* Applied as $22/kW per month, November to March

Appendix D provides more discussion around the customer impacts on Residential Tariffs proposed.

17.10.3 The proposed tariff structures for off-peak controlled load

OPCL is a companion tariff to residential and some business tariffs that has been available for many years and offers a discounted tariff for a particular ToU appliance during the night and early morning 11.00pm to 7:00am. This was augmented with a 'solar sponge' option offering an additional off-peak period between

10:00am and 3:00pm[17]. To diversify the starting loads, the start times for the controlled loads on more modern meters are randomised over one hour commencing at 11:00pm. Older meters start time is determined by a clock in the meter. This tariff is not offered in isolation and must be paired with an appropriate Residential or Business tariff. The tariff is closed to new business customers.

It is recognised that customers upgrade appliances (including hot water services) over time, and the use of OPCL is declining as the following chart demonstrates. The introduction of solar and interval metering, combined with ToU tariffs will offer incentives for customers to manage their demands across the day and shift loads, including the traditional off-peak loads where it is economic and where they are able to do so. It may be that some customers will use some of their surplus solar energy to heat water in the future.

The proposed tariff structures by meter type for OPCL are as follows:

- **Type 5 and Type 6 meters -** Existing Type 5 and Type 6 meters with SAPN-controlled time clocks will remain in use unless the customer's service is upgraded due to customer driven changes, or they opt for an alternative Type 4 meter with their retailer. Any changes to the times including the addition of the solar sponge off-peak time would require a change to the time clock at the customer's meter.
- **Type 4 meters -** For customers with a Type 4 meter, a slightly different controlled load tariff will be offered. Off-peak will be from 11:30pm to 6:30am, peak between 6:30am and 9:30am, a solar sponge tariff for 9:30:am to 3:30pm, then peak from 3:30pm to 11:30pm. Retailers are asked to randomise the start of these modern meters.

In summary, there are in effect three forms of OPCL available to customers:

- **OCPL through time clocks** – where the customer accesses the OCPL tariff through time clocks attached to the metering installation.
- **Retailer lead options** – where the customer accesses OPCL tariffs through their retail tariff based on choices that the retailer makes and offers the customer.
- **Customer lead options** – where the customer takes a 'ToU' tariff or a 'Prosumer' tariff and manages their energy usage within the peak and off-peak times.

Whilst the number of OPCL installations is declining, there is still a need to offer these OPCL tariffs for the foreseeable future. It is expected that customers will migrate to the ToU tariffs if they are comfortable with managing their loads within those off-peak times or will migrate with interval meters to an OPCL-ToU tariff. A summary of proposed OPCL tariffs is in Table 17.9.

Table 17.9: Controlled load tariffs proposed

Tariff	Tariff structure	Requirements	Key features and considerations
Companion Controlled Load (Hot Water) Tariffs			
Off-peak controlled load	Flat rate	Legacy meter (Type 5, 6)	The time clock is managed by SA Power Networks, and typically involves supply usage between 11:00pm to 7:00am and from 10:00am to 3:00pm (the 'solar sponge' option is not available for those customers receiving the 44 cents premium FiT payments). The usage network price will be the same as the residential ToU off-peak network price. A randomised start time occurs on many of the more modern meters.
Off-peak controlled load	Peak and off-peak rates	Type 4 Interval meter Type 5 Legacy meter	For Type 4 meters, the time clock is managed through the meter by the retailer and the metering coordinator. For Type 5 meters, the time clock is adjusted manually. The preferred time periods of use are from 11:30pm to 6:30am and from 9:30am to 3:30pm (solar sponge) with a randomised start time of at least one hour for such equipment (to reduce the coincident peak start load). The off-peak network price of the residential ToU tariff applies for off-peak usage. Usage outside these times is at the same price as the residential ToU peak network price.

[17] The Solar Sponge option of 10:00am to 3:00pm is not available to those customers receiving the 44 cents premium solar Feed-in Tariff (FIT).

Table 17.10: Off-peak Controlled Load tariffs – NUoS Forecasts

			$pa	c/kWh			
OPCL tariff	Tariff structure	Metering	Supply charge	Peak usage charge	Off-peak usage charge	Solar sponge usage charge	Usage charge
Off-peak controlled load	Single rate	SAPN meter (Type 5, 6)	-	-	-	-	7.2
Off-peak controlled load	ToU	Retailer interval meter (Type 4 only)	-	18.0	7.2	3.6	-

Note: The Supply Charge for OPCL is not relevant as this charge is covered by the companion tariff

17.10.4 The proposed tariff structures for the small business tariff class

Small business customers have a different load profile to the residential customers. Whilst many businesses operate in the traditional five days per week and around 9:00am to 5:00pm, there are a number of small businesses that operate later in the day (with demand coinciding with the residential and system peak), and through non-work days. The small business group is quite diverse and includes small business on old legacy tariffs, small businesses on new tariffs, and a group of customers who have been on larger business tariffs, but due to reductions in their energy needs are now classed as small business.

Like other groups, setting tariffs for this class needs to provide the right price signals (empowering the customer), whilst maintaining equity and simplicity in tariff design, and meeting cost reflectivity.

Within this customer group, there is a diverse mix of energy volumes and demand patterns, including significant variance in the use of energy during the peak demand period we experience in the 5:00pm to 9:00pm period. This is considered in the customer impacts for this group.

The tariffs for this group of customers need to ensure that:

- the incremental costs of connection in the low voltage network are shared equitably across this group; and
- the upstream high voltage network is also equitably shared where these costs are driven by demand in the 5:00pm to 9:00pm 'all days of the week' in the period of November to March. The tariff design could include a demand charge for this customer group, but some small business customers have not had a demand charge, so a simpler measure is to adopt a ToU charge during this time.

The tariff structures can therefore be developed to deliver the following for Type 4 and Type 5 meter installations for most small businesses:

- Peak charge: 5:00pm to 9:00pm All days November to March
- Shoulder charge: 7:00am to 9:00pm work days (excluding the peak times)
- Off peak charge: 9:00pm to 7:00am work days and all weekend time (excluding the Peak times).

An anytime demand charge (maximum 30-minute interval, rolling 12-month reset) also applies to those small businesses using more than 70kVA in demand. These customers represent a few percent of small business only.

A summary of proposed tariff structures for small business is presented in Table 17.11.

Table 17.11: Small business tariffs proposed

Business tariff	Tariff structure	Requirements	Comments
Small business			
Small business – Single rate	Supply charge + flat rate	Accumulation meter (Type 6)	The only tariff option for a small business with single-rate Type 6 metering. The companion tariff for controlled load (hot water) is available for those consumers currently using controlled load.
Small business – Two rate	Supply charge + peak and off-peak rates	Accumulation meter (Type 6)	The only tariff option for a small business with two-rate Type 6 metering. The peak and off-peak times are determined by the metering, which may be peak 7:00am to 9:00pm five days a week (Monday to Friday) or possibly all days of the week. Off-peak at all other times. The pricing will be similar to the small business ToU tariff. The companion tariff for controlled load (hot water) is available for those customers currently using controlled load.
Small business – ToU	Supply charge + ToU rates	Type 4 Interval meter - remotely read Type 5 Legacy meter - manually read	Default tariff for small business with Type 4 or Type 5 metering. The same supply charge applies as small business single-rate: • peak is 5:00pm to 9:00pm local time on all days during November through March • Shoulder is 7:00am to 5:00pm work days November to March, and 7:00am to 9:00pm April to October, and • off-peak is all other times. • Anytime demand charged on the highest half-hour demand during the last 12 months where the customer exceeds 70kVA. Lower usage rates apply.
Small business – Unmetered	Usage rates	Unmetered (Type 7)	Used for streetlighting, traffic lights and other unmetered supplies

Table 17.12: Small business tariffs – 2020-21 NUoS Forecast

			$pa	$/kW pa	$/kW pa	c/kWh			
Small business tariff	**Tariff structure**	**Metering**	**Supply charge**	**Actual peak demand charge**	**Anytime maximum demand charge**	**Peak usage charge**	**Shoulder usage charge**	**Off-peak usage charge**	**Usage charge**
Small business – Single rate	Supply charge + flat rate	Accumulation meter (Type 6)	186	-	-	-	-	-	13.6
Small business – Two rate	Supply charge + peak and off-peak rates	Accumulation meter (Type 6)	186	-	-	15.2	-	8.0	-
Small business – ToU < 70kVA	Supply charge + ToU rates	Type 4 Interval meter - remotely read Type 5 Legacy meter - manually read	186	-	-	19.9	14.2	8.4	-
Small business – ToU and MD	Supply charge + anytime demand rates + ToU rates	Interval meter (Type 4)	186	-	16.1	19.9	12.7	7.4	-
Small business – SBD Transition	Supply charge + peak demand rates + ToU rates	Interval meter (Type 4)	186	11.4 per month	5.7 per month Shoulder	-		-	7.7
Streetlights and unmetered loads	Unmetered	Unmetered (Type 7)	-	-	-	-	-	-	8.5

Due to the relatively large number of customers that will 'churn' to new interval Type 4 meters in the future, it is proposed to offer the following:

- Small businesses with demand of less than 70 kVA - the default tariff will be the ToU tariff, but with the option of small business customers able to opt-in to the ToU with Demand tariff. This includes all small businesses that use Whole Current[18] metering, as such installations cannot exceed 70 kVA
- Small business with demand greater than 70 kVA – the default tariff will be the ToU with anytime maximum demand, and with no 'opt-out' options.

The anytime maximum demand will be calculated on a rolling 12-months basis but reset on a change of customer.

Refer to Appendix D for more discussion around the customer impacts on small business tariffs proposed in this TSS.

17.10.5 The proposed tariff structures for large business

Large business has three tariff classes, but the parameters and considerations are quite similar. It is the rates that will change within the tariff structures that will differentiate the three classes. Those classes are:

- Large business - low voltage
- Large business - high voltage
- Large business - major business

The structure of the proposed large business tariff will incorporate the following components which are discussed below. (Further analysis on the reasoning behind these components, how they are applied, and the customer impacts is contained within the Appendix D).

- **Supply charge** – varies based on supply point. Structure does not change from that previously offered. This recovers some of the connection costs.
- **Anytime demand** – based on the highest half hour demand during the year. This is designed to recover the assets that are applied to the connection of the customer and used to support local network pricing, eg the demands during business hours, or localised peaks required by that customer for example.
- **Peak demand** – based on the relevant measurement time for CBD and non-CBD areas. This peak demand charge recognises the peak congestion in the network. The Peak Demand is measured during November to March:
  - in a 6-hour interval between 11:00am and 5:00pm on work days for the CBD; and
  - in a 4-hour interval between 5:00pm and 9:00pm on work days in non-CBD areas.
- **ToU energy** – based on peak and off-peak usage times where peak is 7:00am to 9:00pm local time on work days (excludes public holidays), plus from 5:00pm to 9:00pm on non-work days during November through March; and off-peak is all other times.

Actual peak and agreed peak demand

As mentioned in the opening to this subsection, our network peak has shifted due to the introduction of a significant amount of solar generation embedded in the network. This technology change has moved the network peak to a later time in the day. Understandably, the large business peak load has not moved to the same extent, as this is driven by the operating times of business. The solar take-up in business is increasing which will reduce business usage of the network.

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[18] Whole Current meters connect directly to the supply rather than through a Current Transformer which is applied to HV metering connections.

Within the peak demand charge, there are tariff components proposed for the peak demand values which comprise:

- ***Agreed annual demand:*** where the customer agrees a value for the peak demand each year, and incurs a charge based on an agreed kVA for the five-month period from November to March being the average demand in the peak window (six hours 11:00am to 5:00pm for CBD and a four-hour window 5:00pm to 9:00pm for non-CBD). The agreed demand charge is smoothed over the year. The annual demand is reset according to the rolling 12 months.
- ***Actual demand***: some customers have seasonal demand where peak activity occurs in only a few of the summer months. The charge for the actual demand is 125% of the annual demand. This would suit a customer with a seasonal load within the peak demand months from November to March which is not experienced for the full period. This provides customers with choice and empowers the customers to make decisions on how they can manage their seasonal loads whilst maintaining equity in charging across the large business tariff classes. (If the annual demand price was $100/kVA, that equates to $20/kVA per month for 5 months November to March. The actual demand price is 125% of that, ie $25/kVA per month).

We propose that customers will need to choose to have either an agreed demand or an actual demand option in their tariff.

It is proposed that in the longer term, we may be able to offer a combination of agreed demand and actual demand to suit customers who have a consistent base load and have some seasonal peak load. They would then be able to pay an incremental amount based on the incremental actual demand without resetting the agreed demand base. This will allow customers to adapt their loads with embedded generation for example and allow them to spread loads across the year. Whilst simple to apply in concept for a customer, the combination agreed and actual requires some enhancements to billing systems by the network and retailers to support this option.

The anytime demand

The anytime demand for large business is the highest average demand across a 30-minute window in the year. The anytime demand is reset on a rolling 12-month basis except if the supply is for a backup supply connection and the connection request is for a higher nominated amount. For new connections, the nominated amount would apply as the minimum for the first three years.

Locational influence – why the CBD is different

The structure of tariffs proposed for large business recognises the locational differences of peak demand during the day, and in particular the differences driven by the load in the Adelaide CBD. The legislative requirement[19] for State-wide pricing for small customers does not apply to large business customers enabling this distinction for locational differences in the Large business tariff class. In this case, the CBD is defined as the area bounded by the West, South and East parklands, and the area south of the River Torrens, but including the businesses immediately north of the river between King William Road and Montefiore Road and south of Pennington Terrace.

The effect of solar in the CBD is low compared to other parts of the state due to the lack of suitable roof space relative to the significant commercial loads experienced in the CBD. This is supported by the analysis included on the difference between work days and non-work days for the CBD as identified in Section C.6 of Appendix C, attached. Therefore, there is a need to consider tariffs for the CBD and the non-CBD separately to reflect the differences in the timing of the underlying demands.

[19] *Electricity Act of South Australia 1996 (as amended). Section 35A (2)*

The demand charge for the CBD will be higher than the non-CBD due because of a higher alignment with the CBD loads, but the usage charge will be lower than the non-CBD as a consequence.

The development of tariffs for the large business still needs to follow the principles of empowering the consumer, fairness and equity, and simplicity. So, the tariffs for large business will incorporate similar prices, but that the times during the day for the measurement of the peak demand will differ between the CBD customers and the non-CBD customers.

A summary of proposed tariff structures for large business is outlined in Table 17.13.

Table 17.13: Large business tariffs proposed

Tariff	Tariff structure	Requirements	Key features and considerations
Large business*			
CBD – Demand	Supply charge + actual/agreed demand rates + ToU rates	Remotely read interval meter (Type 4)	• New mandatory tariff for large business in the CBD. • Demand charge based on the highest daily average maximum demand during 11:00am–5:00pm on work days only from November through March. • Anytime demand charged on the highest half-hour demand during the year. • Peak and off-peak usage rates apply at the times used for small business two-rate, but at much lower rates ie 7:00am – 9:00pm work day year-round.
Non-CBD – Demand	Supply charge + actual/agreed demand rates + time of-use rates	Remotely read interval meter (Type 4)	• New mandatory tariff for large business outside the CBD. • Demand charges based on the highest daily average maximum demand during 5.00pm–9.00pm any day from November through March. • Anytime demand charged on the highest half-hour demand during the year. • Peak and off-peak usage rates apply at the times used for small business ToU, but at much lower rates. In this tariff, there is no shoulder time, and this would be treated as peak. ie peak is 7:00am – 9:00pm work days plus 5:00pm – 9:00pm non-work days (November to March only)

*The reason for this distinction between CBD and non-CBD is because the solar penetration in the CBD is different to the rest of South Australia, resulting in a different peak demand profile. The CBD includes the area surrounded by the parklands, including the River Torrens precinct, but excludes the North Adelaide area.

Table 17.14: Large LV business tariffs – 2020-21 NUoS Forecast (CBD and Non-CBD)

			$pa	$/kVA pa	$/kVA pa	$/kVA pa	c/kWh			
Large business tariff	**Tariff structure**	**Metering**	**Supply charge**	**Annual peak demand charge**	**Actual peak demand charge**	**Anytime maximum demand charge**	**Peak usage charge**	**Shoulder usage charge**	**Off-peak usage charge**	**Usage charge**
Large business – ToU - annual demand	Supply charge +annual demand + ToU rates	Type 4 Interval meter - remotely read Type 5 Legacy meter - manually read	2,076	64.6		44.3	6.2	-	4.8	-
Demand > 1,000 kVA	Supply charge +annual demand + ToU rates	Type 4 Interval meter - remotely read Type 5 Legacy meter - manually read	23,408	64.6		23.0	6.2	-	4.8	-
Large business – ToU - annual demand	Supply charge +annual demand + ToU rates	Type 4 Interval meter - remotely read Type 5 Legacy meter - manually read	2,076	-	16.2 per month	44.3	6.2	-	4.8	-
Large business – ToU - annual demand Transition	Supply charge +annual demand + ToU rates	Type 4 Interval meter - remotely read Type 5 Legacy meter - manually read	173	-	11.4 per month	5.7 per month Shoulder	-	-	-	7.5
Large business – single rate – Transition	Supply charge + Single rate	Accumulation meter (Type 6)	173	-	-	-	-	-	-	16.3
Large business – two rate – Transition	Supply charge + two rate	Accumulation meter (Type 6)	173	-	-	-	-	18.3	9.6	-

Table 17.15: Large HV business tariffs – 2020-21 NUoS Forecast (CBD and Non-CBD)

			$pa	$/kVA pa	$/kVA pa	$/kVA pa	c/kWh			
Large business tariff	**Tariff structure**	**Metering**	**Supply charge**	**Annual peak demand charge**	**Actual peak demand charge**	**Anytime maximum demand charge**	**Peak usage charge**	**Shoulder usage charge**	**Off-peak usage charge**	**Usage charge**
Large business – annual demand	Supply charge +annual demand + ToU rates	Interval meter, - remotely read (Type 4)	14,220	41.8	-	44.3	3.9	-	3.0	-
Large business – actual demand	Supply charge +actual demand + ToU rates	Interval meter, - remotely read (Type 4)	14,220	-	10.4 per month	44.3	3.9	-	3.0	-
Large business – annual demand <500kVA	Supply charge +annual demand + ToU rates	Interval meter, - remotely read (Type 4)	2,076	64.6	-	44.3	6.0	-	4.6	-
Large business – HBD Transition	Supply charge +annual demand + ToU rates	Interval meter, - remotely read (Type 4)	173	-	11.4 per month	5.7 per month Shoulder	-	-	-	7.3

The '<500 kVA' and 'HBD transition' are for a few smaller HV business customers who currently utilise similar tariffs.

Refer to Appendix D for more discussion and analysis on Large business impacts for:

- Large business - Low Voltage (Appendix D.5.1)
- Large business - High Voltage (Appendix D.5.2)
- Large business - Major business (Appendix D.5.3)

Table 17.16: Non-locational Major Business – 2020-21 NUoS Forecast

			$pa	$/kVA pa	$/kVA pa	$/kVA pa	c/kWh			
Major business tariff	**Tariff structure**	**Metering**	**Supply charge**	**Annual peak demand charge**	**Actual peak demand charge**	**Anytime maximum demand charge**	**Peak usage charge**	**Shoulder usage charge**	**Off-peak usage charge**	**Usage charge**
Zone substation – agreed demand	Supply charge +agreed demand + ToU rates	Interval meter, - remotely read (Type 4)	Individually calculated	23.6	-	41.0				1.5
Sub-transmission – agreed demand	Supply charge +agreed demand + ToU rates	Interval meter, - remotely read (Type 4)	Individually calculated	18.2	-	14.8				1.3

17.10.6 Tariff trials

We are trialling an agreed demand tariff for selected large customers in the Riverland. This tariff trial is designed to:

- target peak demand usage on extreme summer days (eg the peak demand is only measured on days when the temperature at Renmark is forecast to be 40 degrees Celsius or higher);
- test the approach to measuring separate charges for peak demand and for anytime demand that we are proposing in the 2020–2025 period;
- test the consumer experience with this opt-in tariff, and whether a tangible change in regional demand can be achieved by a consumer demand response; and
- test our ability to implement a bespoke tariff.

We are trialling this as a consumer-rebate tariff, where the consumer continues to be billed by their retailer under the standard agreed demand tariff, but the network will rebate the consumer directly at the end of the year if the bespoke tariff is to their advantage. If successful, this tariff may be retained in the 2020-25 period.

We are also proposing to trial two of the residential tariffs proposed for 2020-25. As part of our proposals to 'bring hot water back under control', we propose to trial in 2019-20 two pricing structures that are planned for the 2020-25 RCP. They are as follows:

- Type 4 meter off-peak controlled load ToU, where retailers control the time windows via their interval meters. The ToU tariff incentivises the customer to move load away from the congested periods to periods of low network demand, particularly into the 'solar trough'.

- The Type 4 and Type 5 meter ToU tariff, where customers and retailers with storage/flexible/managed load can access a ToU tariff to respond to incentives to shift load away from congestion periods, particularly towards the solar sponge. Customers wishing to use their solar export to heat water and other OPCL loads (eg EV), perhaps with home management systems and/or batteries or perhaps with pool pumps, might choose to participate if retailers choose to offer the trial. Up to 7,000 customers could be accommodated in this trial (1% of residential customers or 6% of customers with Type 4 or Type 5 interval meters in 2019-20).

17.11 Assigning customers to tariff classes

Within each of our five standard control services tariff classes we offer a number of different network tariffs. The basic structure of our tariffs is very similar to that of other electricity distributors in the NEM with three key tariff components:

- A fixed supply charge ($ per day, month or quarter)
- A peak demand charge to send a forward Long Run Marginal Cost (**LRMC**) price signal ($ per kW or kVA per day)
- A volume charge ($/kWh) to recover residual costs not recovered by the other two elements

Many small customers do not use a peak demand charge today, therefore the volume charge recovers a greater portion of total costs. Customers using Type 6 legacy meters may not have any tariff choice unless they request a meter change from their retailer.

Customers need to be assigned to a particular tariff in accordance with the NER. The requirements concerning the assignment and re-assignment of customers to tariff classes are set out in clause 6.18.4 of the Rules and any directions provided in the AER's Final Decision (revenue determination).

17.11.1 Regulatory Requirements

Rules requirements

In making a distribution determination, the AER is required to formulate provisions for the assignment and re-assignment of customers to tariff classes, in accordance with the principles set out in clause 6.18.4 of the Rules. This Rule covers the following matters:

1) factors governing the assignment of customers to tariff classes such as:
    - nature and extent of usage;
    - nature of the connection; and
    - whether remotely read interval metering has been installed.
2) customers with similar connections and usage should be treated on an equal basis;
3) equitable treatment of customers with micro-generation;
4) the review and assessment of the DNSP decision on tariff class assignment; and
5) the review of DNSPs' tariff structures containing energy or demand related charges.

17.11.2 Requirements of the AER's Final Decision

In accordance with the principles in clause 6.18.4 of the Rules the AER will make a determination on the procedure to apply to assigning or re-assigning customers to tariff classes as part of its final decision.

These provisions will cover the following aspects:

- Assignment of existing retail customers to tariff classes at the commencement of the 2020-25 RCP (on 1 July 2020)
- Assignment of new retail customers to a tariff class during the 2020-25 RCP (from July 2020 to June 2025)
- Re-assignment of existing retail customers to another existing or a new tariff class during the 2020-25 RCP (from July 2020 to June 2025)
- Objections to proposed assignments and re-assignments

To inform the AER on this process, SA Power Networks has set out below, the process on how we propose to deal with these aspects of the rules.

Assignment of existing retail customers to a tariff class at the commencement of the 2020-25 RCP

1) SA Power Networks' retail customers will be "assigned" to the tariff class to which SA Power Networks was charging them immediately prior to 1 July 2020 if:
   a) they were an SA Power Networks retail customer prior to 1 July 2020; and
   b) they continue to be a retail customer of SA Power Networks as at 1 July 2020.

Assignment of new retail customers to a tariff class during the 2020-25 RCP

2) If, after 1 July 2020, SA Power Networks becomes aware that a person will become a retail customer, then SA Power Networks must determine the tariff class to which the new customer will be assigned.

3) In determining the tariff class to which a retail customer or potential retail customer will be assigned, or re-assigned, in accordance with point 2 or 5 of this section, SA Power Networks must take into account one or more of the following factors:
   a) the nature and extent of the retail customer's usage
   b) the nature of the retail customer's connection to the network
   c) 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.

4) In addition to the requirements under point 3 above, SA Power Networks, when assigning or re-assigning a retail customer to a tariff class, must ensure:
   a) retail customers with similar connection and usage profiles are treated equally; and
   b) retail customers who have micro–generation facilities are not treated less favourably than retail customers with similar load profiles without such facilities.

Re-assignment of existing retail customers to another existing or a new tariff class during the next Regulatory Control Period

5) SA Power Networks may re-assign a retail customer to another tariff class if the existing retail customer's load characteristics or connection characteristics (or both) have changed such that it is no longer appropriate for that retail customer to be assigned to the tariff class to which the retail customer is currently assigned or a retail customer no longer has the same or materially similar load or connection characteristics as other retail customers on the retail customer's existing tariff class, then it may re-assign that retail customer to another tariff class. In determining the tariff class to which a retail customer will be re-assigned, SA Power Networks must take into account points 3 and 4 above.

Objections to proposed assignments and re-assignments

6) SA Power Networks must notify a customer's retailer in writing of the tariff class to which the retail customer has been assigned or re-assigned, prior to the assignment or re-assignment occurring.

7) A notice under point 6 above must include advice informing the customer's retailer that they may request further information from SA Power Networks and that the retail customer may object to the proposed re-assignment. This notice must specifically include:

   a) a written document describing SA Power Networks' internal procedures for reviewing objections;
   b) that if the objection is not resolved to the satisfaction of the customer's retailer under SA Power Networks' internal review system within a reasonable timeframe, then, to the extent that resolution of such disputes is within the jurisdiction of the Energy and Water Ombudsman of South Australia (**EWoSA**), or like officer, the customer's retailer is entitled to escalate the matter to such a body; and
   c) that if the objection is not resolved to the satisfaction of the customer's retailer under SA Power Networks' internal review system and the body noted in clause 7b above, then the customer or its

retailer is entitled to seek a decision of the AER via the dispute resolution process available under Part 10 of the National Electricity Law (**NEL**).

8) If, in response to a notice issued in accordance with point 7 above, SA Power Networks receives a request for further information from a customer's retailer, then it must provide such information within a reasonable timeframe. If SA Power Networks reasonably claims confidentiality over any of the information requested by the customer's retailer, then it is not required to provide that information to the customer's retailer. If the customer's retailer disagrees with such confidentiality claims, he or she may have resort to the dispute resolution procedures referred to in point 7 (as modified for a confidentiality dispute).

9) If, in response to a notice issued in accordance with point 7 above, a customer's retailer makes an objection to SA Power Networks about the proposed assignment or re-assignment, SA Power Networks must reconsider the proposed assignment or re-assignment. In doing so SA Power Networks must take into consideration the factors in points 3 and 4 above and notify the customer's retailer in writing of its decision and the reasons for that decision.

10) If a customer's retailer's objection to a tariff assignment or re-assignment is upheld by the relevant body noted in points 7b and 7c above, then any adjustment which needs to be made to tariffs will be done by SA Power Networks as part of the next annual review of prices.

11) If a customer's retailer objects to SA Power Networks' tariff class assignment SA Power Networks must provide the information set out in point 7 above and adopt and comply with the arrangements set out in points 8, 9 and 10 above in respect of requests for further information by the customer's retailer and resolution of the objection.

17.11.3 Our response to the assignment/re-assignment requirements

In this section of the TSS, SA Power Networks describes the process it applies to the initial assignment of customers to tariffs and to their re-assignment. Individual tariffs have been grouped within tariff classes in this proposed TSS in accordance with a well-established approach. This existing approach to managing tariff assignment and re-assignment is proposed to continue and is demonstrated to align with the requirements established by the AER.

Assignment of new customers to a tariff class and tariff

The process whereby new customers are assigned to tariff classes and tariffs, following the receipt of a connection application by the customer or their retailer, follows in

Figure **17.19**. In the application of this process, a customer that lodges an application to modify or upgrade an existing network connection is treated in the same manner as a new customer.

Figure 17.19: Assignment of new and upgraded customer connections to tariff classes

CUSTOMER TYPE	METER	TARIFF OPTIONS	TARIFF CLASSES / TARIFFS	TARIFF DESCRIPTION
			MAJOR BUSINESS	
Sub-transmission	Type 4	Default	STRD Annual Demand	Cost reflective
	Type 4	Opt-out	STRMD Monthly Peak Demand	Cost reflective
Zone Substation	Type 4	Default	ZSND Annual Demand	Cost reflective
	Type 4	Opt-out	ZSNMD Monthly Peak Demand	Cost reflective
			HIGH VOLTAGE BUSINESS	
11 kV connection	Type 4	Default	HVD Annual Demand	Cost reflective
	Type 4	Opt-out	HVMD Monthly Peak Demand	Cost reflective
			LARGE LV BUSINESS	
LV Business >160MWh pa	Type 6	Closed	LBSRT	Energy only
	Type 6	Closed	LB2RT	Energy only
	Type 4,5	Default	LVD Annual Demand	Cost reflective
	Type 4,5	Opt-out	LVMD Monthly Peak Demand	Cost reflective
			SMALL BUSINESS	
LV Business <160MWh pa	Type 6	Closed	B2R	Energy only
	Type 6	Closed	BSR	Energy only
	Type 6	Closed	OPCL	Energy only
	Type 4,5	Default (<70kVA)	ToU	Cost reflective
	Type 4,5	Opt-out (<70kVA)	ToU + MD	Cost reflective
	Type 4,5	Default (>70kVA)	ToU + MD	Cost reflective
			RESIDENTIAL	
Residential	Type 6	Closed	RSR	Energy only
	Type 4,5	Default	ToU	Cost reflective
	Type 4	Opt-in	Prosumer	Cost reflective
			CONTROLLED LOAD	
Residential OCPL	Type 5,6	Default	OPCL	Energy only
	Type 4	Default	OPCL-ToU	Cost reflective

Notes: For Large Business

- For Large Business in the CBD, Peak Demand is measured between 11:00am and 5:00pm November to March .
- For Large Business in South Australia not in the CBD, Peak Demand is measured between 5:00pm and 9:00pm November to March.
- Major Customers with > 10MVA or > 40 GWh at a site (or adjacent sites) have locational transmission charges.
- Variations of these tariffs apply to back up supplies and to generation house supplies.
- Customer sites with multiple supplies e.g. backup supplies will pay the supply and anytime demand charge required by each supply. The usage and peak demand charges are applied to the total load across the multiple supplies.
- Generation house supplies do not incur usage charges. Where a load and generation connection are combined, the site is treated as a customer, not as a generator.

The two major decisions that determine the tariff class assessment are as follows:

- the nature of a customer's usage: (ie residential or business); and
- for business customers only, the nature and extent of the associated connection to the network (the connection voltage, whether located within in the network or directly connected to a zone substation), and if the business customer is connected at LV then the annual consumption (above or below 160MWh pa) applies as a further test.

Note that large LV businesses with Type 6 (accumulation) meters cannot utilise the default Business Demand (**BD**) tariff which requires interval metering. These customers (with a Type 6 meter) will be assigned to either large business single rate (**LBSR)** or large business two rate (**LB2R)**.

Assignment to cost-reflective tariffs – Thresholds and triggers

The specific thresholds and triggers that will result in a small customer (residential or business) being assigned to a cost-reflective tariff comprise:

- from July 2020, all residential customers with a Type 4 or Type 5 meter using single rate tariffs will be reassigned to the residential ToU tariff
- from July 2020 all OPCL customers with a Type 4 meter will be reassigned to the OPCL ToU tariff
- all small business with a Type 4 or Type 5 meter with demand exceeding 70kVA will be assigned to the small business ToU + MD tariff
- all new/alterations to supply small businesses requiring new CT Type 4 metering to be installed will be reassigned to the small business ToU with maximum demand tariff (CT metering, above 70 kVA), from July 2020; and

Alterations to supply include those alterations that would require a new meter to be installed, for example:

- physical supply changes to an existing supply that increase the capacity of supply to a customer, eg converting to three phase power from single phase, or having the available capacity to a property increased; and
- installing an inverter to enable import and expert of energy to the network.

Alterations to supply/new customers do not include:

- a change in the name of the existing account holder;

Customers with micro-generation

As SA Power Networks' tariff class assignment process is applied to the *net* customer demand supplied from the network, it does not distinguish between customers that have micro-generation and those without.

The only aspects of the connection process that distinguish customers with micro-generation are technical requirements, principally to ensure public and employee safety in the event of disconnection of supply to a site with generation.

Re-assignment of existing customers to another existing or a new tariff during the 2020-25 RCP

General assignment of customers

Within each tariff class, there has been and will continue to be movement between individual tariffs. This is particularly the case with the customers in the small business and large LV business tariff classes.
The five tariff classes that SA Power Networks has established are sufficiently broad to ensure that all the existing customers are within the appropriate tariff class and that it is unlikely that customers will seek to migrate or be reclassified to a different tariff class during the course of the determination. Transfer between tariff classes would be limited to circumstances where the nature of usage or level of

consumption changed significantly, for example where a residence was redeveloped to become a small business such as a medical surgery or office.

Transfer can also occur between the small business and large LV business tariff classes if a customer's consumption moves across the 160MWh threshold. SA Power Networks proposes to review customers' consumption in April each year, using data collected up to 31 March. We will advise retailers of any resultant tariff class/tariff changes in May. The changes will apply from 1 July in that year.

SA Power Networks follows the same processes for customers being re-assigned to another tariff within a tariff class as would apply to customers being re-assigned to another tariff class. Customers are able to object to such re-assignments in the same manner that they are permitted to object to a tariff class re-assignment.

Assignment of small business customers

Large business customers are assigned to a demand tariff because of the size of demand and the nature of their consumption, however it is possible that we can offer a demand tariff to small business customers (consuming less than 160MWh per annum) with Type 4 interval metering where it is appropriate to do so. In this section we will discuss the demand characteristics of a subset of small business customers and the issues that this presents. These customers represent less than 6,000 of the 95,000 small business customers connected to our network.

In considering these small business customers, we have had regard to the various characteristics of energy consumption by customers which have some of the attributes of a large business customer. However, they are not a large business customer by the nature of their consumption being less than the threshold of 160MWh per year. These attributes and the variation in customers usage patterns allow for some diversification of loads across the small business class which can be due to:

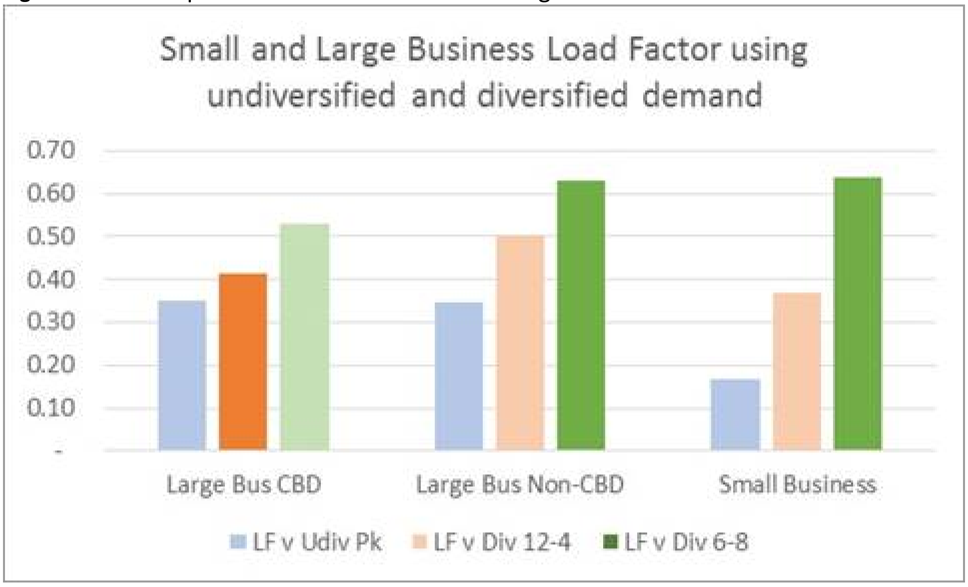
- businesses operating at reduced hours during the day;
- intermittent use throughout a year or week (such as storm water pumping for example);
- seasonal use (such as grain handling or irrigation); and
- different operating hours during the day (eg an early morning start for a bakery, and a late start for a small pizza bar operating predominately in the evening).

The load factors evident in the small business tariff class can be quite different to large business load factors and need to be considered in the development of tariffs and the assignment of customers to tariffs within this class. If one of our seasonal business examples described above only operated for three or four days of the year, its load factor would be 1%. Even a small business operating for four hours each day, six days each week would have a load factor of less than 14%. Any demand charges proposed for this tariff class could be very significant in the customer's bill.

To explain this further we have compared the load factors of large business and small business undiversified and diversified demand in the following figure.

The chart demonstrates that whilst the small business has a low load factor at measured 'anytime', it improves if measured in the traditional large business peak period of 12:00pm to 4:00pm, and improves again in the period 6:00pm to 8:00pm where the load factor of small business behaves similarly to the large business non-CBD class.

Figure 17.20: Comparison of small business and large business load factors



Source: SA Power Networks analysis
Load factor versus undiversified peak (LF v Udiv Pk); load factor versus diversified 12pm-4pm peak (LF v Div 12-4); load factor versus diversified 6pm-8pm peak (LF v Div 6-8)

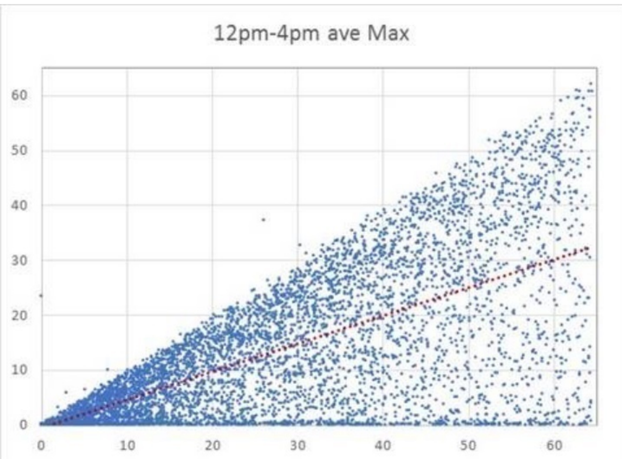
Diversity is important for network providers as it allows for the efficient delivery of network services to customers if it can satisfy the total customer demand over a year without having to build assets to deliver their total undiversified demand. Diversification allows for sharing of assets in the delivery of the annual bundled service and should be recognised in the pricing.

To explain the strength of diversity of the small business class we have compared the anytime maximum demand with the maximum demand for the customers with a maximum demand of less than 70kVA during the year. The charts below compare the anytime demand with:

- their maximum demand between 12:00pm and 4:00pm (Figure 17.21); and
- their maximum demand between 6:00pm and 8:00pm (Figure 17.22).

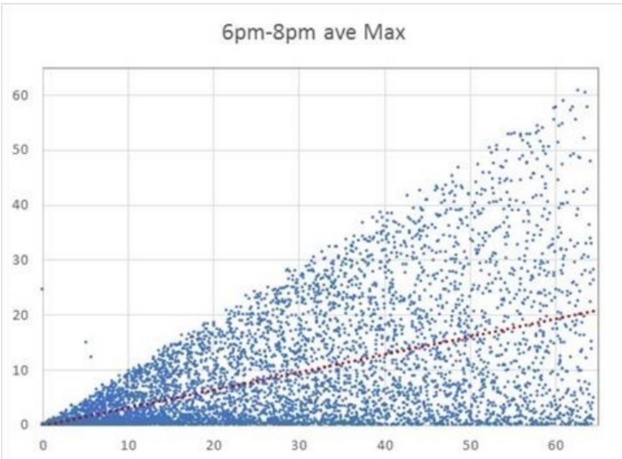
The charts demonstrate that whilst there is significant diversification across this customer class, there is more coincidence between the anytime maximum demand and the early afternoon demand, and more diversification in the evening demand.

Figure 17.21: Small business with demand up to 70kVA – Comparison of Maximum Demand with the Demand observed between 12:00pm and 4:00pm



Source: SA Power Networks analysis

Figure 17.22: Small business with demand up to 70kVA – Comparison of Maximum Demand with the Demand observed between 6:00pm and 8:00pm



Source: SA Power Networks analysis

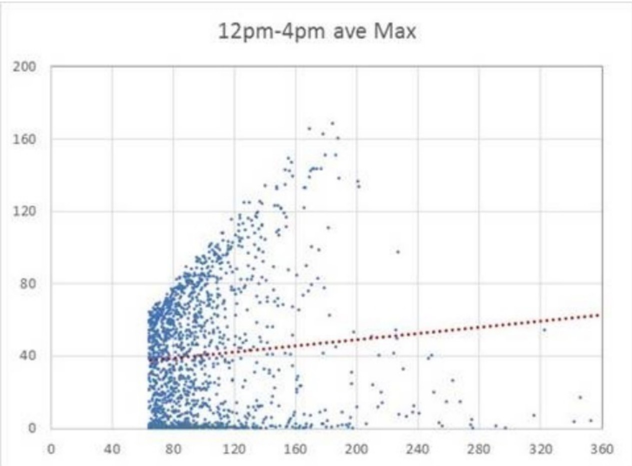
Note: there is a tighter cluster of plots closer to the top of the 12:00pm to 4:00pm than there is to the 6:00pm to 8:00pm. Further, the red line of best fit is clearly lower in the 6:00pm to 8:00pm demonstrating higher diversity in the later time period.

In further support of the strength of diversity of the small business class we have compared the anytime maximum demand with the maximum demand, for the customers with maximum demands of greater than 70kVA. The chart compares the anytime demand with:

- their maximum demand between 12:00pm and 4:00pm (Figure 17.23); and
- their maximum demand between 6:00pm and 8:00pm (Figure 17.24).

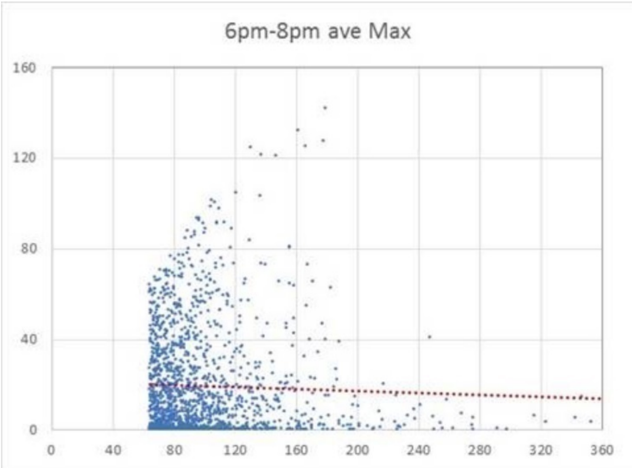
Again, the charts demonstrate the significant diversification across this customer class, especially in the evening demand period.

Figure 17.23: Small business with demand above 70kVA – Comparison of Maximum Demand with the Demand observed between 12:00pm and 4:00pm



Source: SA Power Networks analysis

Figure 17.24: Small business with demand above 70kVA – Comparison of Maximum Demand with the Demand observed between 6:00pm and 8:00pm



Source: SA Power networks analysis

Objections to proposed assignments and re-assignments

The AER has established requirements that SA Power Networks must follow in assigning or reassigning customers to tariff classes and in responding to objections to SA Power Networks' tariff class assignments. The requirements that SA Power Networks must follow have been documented in an internal procedure entitled "Manual 18, Network Tariff Manual". This document is published on SA Power Networks' website[20].

17.12 What do these tariffs mean for customers

If retailers pass the effect of these network tariffs through to customers, customers may be motivated to change consumption patterns to try to reduce their individual bills. This behaviour will increase the utilisation of the network which will help to lower the future price of electricity for all customers over the longer-term.

For residential customers with Type 4 or Type 5 interval meters, the mandatory ToU network prices will change the amounts paid by retailers for each customer. We do not expect that the network price will vary

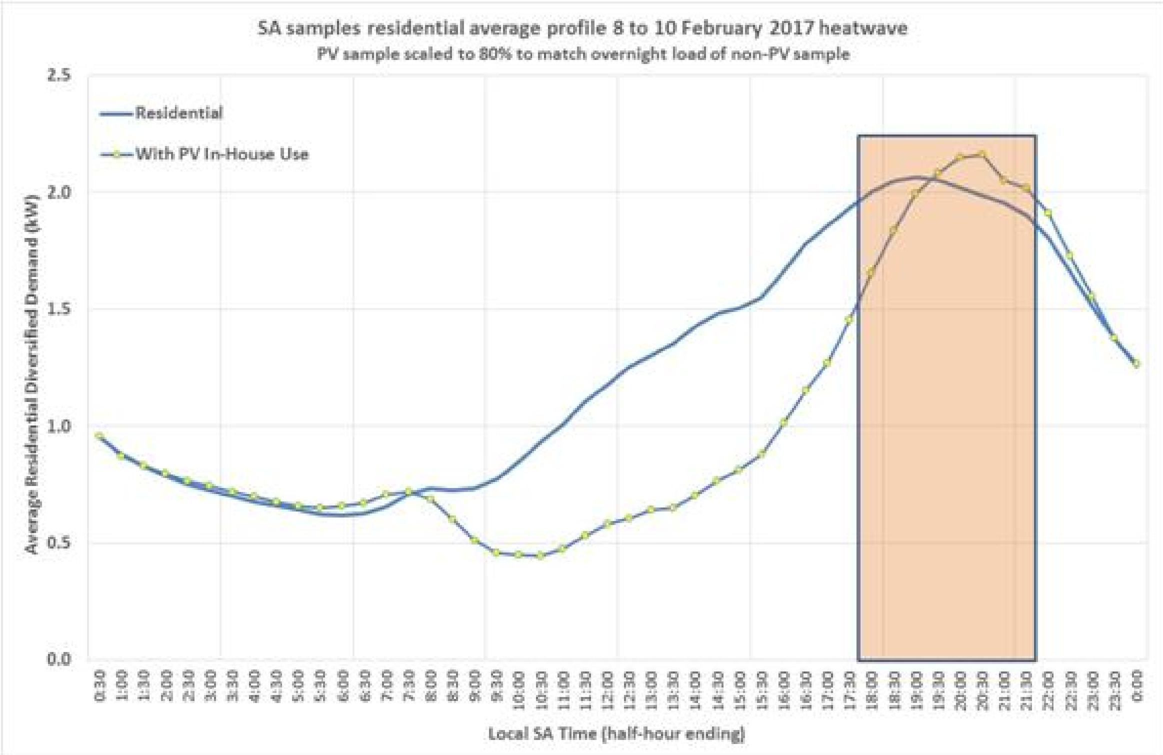
[20] *Manual 18 available at: https://www.sapowernetworks.com.au/public/download.jsp?id=9501*

by more than five percent of the current retail price, which should be manageable for retailers and residential customers.

For the residential 'prosumer' who opts-in to the more complex summer demand tariff, the use of the four-hour window will help to correctly incentivise a demand response. The demand on our network is relatively flat over the four hours from 5:30pm to 9:30pm on extreme days, so it is more reasonable to measure across a four-hour window rather than bill on a single half-hour spike which may just be a combination of air-conditioning and meal preparation, for example.

The average use over the four-hour period is more relevant to the network than the highest half-hour that we have previously proposed, and which residential customers and retailers disliked. Figure 17.25 shows the average extreme summer day profiles for households with and without solar.

Figure 17.25: Residential demand profile with and without solar



Source: SA Power Networks analysis

Figure 17.25 shows the benefit of solar panels with a notable reduction in network demand on extreme days (the lower, green line). Further benefit could be gained if batteries exported during this time after the solar panels have ceased generating electricity but air-conditioning or other load is still required. Whilst this tariff will not be suitable for most residential customers, it will meet the needs of a niche group of prosumers seeking to improve the management of their electricity demand.

17.13 Other considerations

SA Power Networks does not determine the value of energy that customers export to the network. In the past, ESCoSA has set minimum feed-in tariffs for generation export but this price is now determined by retailer competition.

This is not a pricing initiative that SA Power Networks can introduce nor influence. However, we would welcome any initiative to amend retailers' FiT single-rate into a time-of-export rate where the price is lower at times of high export/lower local demand (solar noon) and is higher at times of low export/higher local demand (early evening) as this responds to a congestion issue that faces our network.

At times of solar noon, there is significant export of energy into the network, creating a time of congestion. It may be appropriate to attempt to influence that and provide incentives for customers to export in the morning, and if the customer had storage technology, store energy during the solar noon and export in the evening to match local peak demands.

Whilst this might be possible through structuring tariffs to provide this incentive:

- the ability to move export potential is likely to be low (but increasing with the installation of batteries and 'virtual power plants" over the medium term; and
- the complexity of preparing tariffs to achieve this is likely to be high, and therefore not consistent with the principle of simplicity.

This is something to be considered for future tariff design.

17.14 Pricing methodology

17.14.1 Compliance with rules

This Section demonstrates how SA Power Networks' network tariffs for 2020-25 will comply with the requirements of the Rules and the AER's Final Decision (revenue determination) in respect of the pricing 'X-factors', side constraints and pricing principles.

Rule requirements

Clause 6.18.1A (b) of the Rules specifies that SA Power Networks' TSS must comply with the pricing principles for direct control services. These pricing principles are set out in Rule 6.18.5.

The network pricing objective has been specified in Rule 6.18.5 (a) which requires that our tariff charges should reflect our efficient costs of providing these services to customers using these tariffs. Note that efficient costs are determined by the AER in its regulatory determinations.

The pricing principles set out in clauses 6.18.5 (e) - (j) of the Rules are:

Pricing Principles

(e) For each *tariff class*, the revenue expected to be recovered must lie on or between:
  - (1) an upper bound representing the stand alone cost of serving the *retail customers* who belong to that class; and
  - (2) a lower bound representing the avoidable cost of not serving those *retail customers*.

(f) Each tariff must be based on the *long run marginal cost* of providing the service to which it relates to the *retail customers* assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:
  - (1) the costs and benefits associated with calculating, implementing and applying that method as proposed;
  - (2) the additional costs likely to be associated with meeting demand from *retail customers* that are assigned to that tariff at times of greatest utilisation of the relevant part of the *distribution network*; and

(3) the location of *retail customers* that are assigned to that tariff and the extent to which costs vary between different locations in the *distribution network*.

(g) The revenue expected to be recovered from each tariff must:

(1) reflect the *Distribution Network Service Provider's* total efficient costs of serving the *retail customers* that are assigned to that tariff;

(2) when summed with the revenue expected to be received from all other tariffs, permit the *Distribution Network Service Provider* to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the *Distribution Network Service Provider*; and

(3) comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).

(h) A *Distribution Network Service Provider* must consider the impact on *retail customers* of changes in tariffs from the previous *regulatory year* and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the *Distribution Network Service Provider* considers reasonably necessary having regard to:

(1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one *regulatory control period*);

(2) the extent to which *retail customers* can choose the tariff to which they are assigned; and

(3) the extent to which *retail customers* are able to mitigate the impact of changes in tariffs through their usage decisions.

(i) 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*.

(j) A tariff must comply with the *Rules* and all applicable *regulatory instruments*.

In respect of pricing side constraints, SA Power Networks is required to comply with Rules clause 6.18.6 of the Rules. This clause effectively limits the annual movement of revenue recovery between tariff classes such that any tariff class cannot face increases that are more than 2% higher than the average increase for all tariffs. Complying with this side constraint is a matter for Annual Pricing Proposals and not for this TSS.

SA Power Networks will ensure that the annual increase of each tariff class average DUoS price (c/kWh) is not more than 102% of the average DUoS price increase overall. Note that the side constraint applies to DUoS only and/or the tariff class as a whole, and not to individual tariffs, tariff elements nor individual customer outcomes.

17.14.2 Compliance with NER pricing principles

This section demonstrates SA Power Networks' compliance with the pricing principles set out in clause 6.18.5 of the Rules, in particular the pricing principles set out in paragraphs (e) to (j) set out above.

Clause 6.18.5(e) Stand-alone and Avoidable costs

Paragraph (e) requires SA Power Networks to ensure that the revenue recovered for each tariff class lies between:

- an upper bound, representing the stand-alone cost of serving the retail customers who belong to that class; and
- a lower bound, representing the avoidable cost of not serving those retail customers.

The stand-alone and avoidable cost methodologies are consistent with those used for the 2017-20 TSS, however the calculations have been updated to 2020/21. These approaches are used to calculate the revenues for each standard control services tariff class associated with each cost methodology. These costs are compared with the weighted average revenue derived from SA Power Networks' proposed tariffs.

The revenue expected to be recovered from each of SA Power Networks' tariff classes in 2020/21 is compared with the stand-alone and avoidable costs in the Table 17.17.

Table 17.17: Stand-alone and avoidable distribution network costs 2020-21 ($ M nominal)

Tariff class	Stand-alone cost $m	Tariff revenue $m	Avoidable cost $m
Major business	80	9	6
HV business	94	33	6
Large LV business	268	175	47
Small business	318	142	64
LV residential	689	433	257

Source: SA Power Networks analysis

17.14.3 Long run marginal cost

Paragraph (f) of Clause 6.18.8 of the Rules requires each tariff to be based on the LRMC of providing the service to the customers on that tariff.

SA Power Networks has applied the average incremental cost (**AIC**) approach to determine the network LRMC for our tariff classes. The calculation of our LRMC in this TSS uses our previous LRMC calculation applied for the 2017-20 revised TSS.

These calculations are carried out at the following voltage and voltage transformation levels of the network:

- Sub-transmission (33 kV and 66 kV)
- Zone Substation (11 kV busbar)
- HV Feeder (11 kV system connected)
- Distribution Substation (Low Voltage, connected at the substation busbar)
- LV Feeder (connected to the low voltage network)

The marginal cost at each network voltage level has been determined using the following relationship:

$$LRMC(AIC) = \frac{PV(Growth\ Related\ capex) +\ PV(Growth\ Related\ opex)}{PV(incremental\ demand)}$$

Where:

growth related capex is the annualised capital expenditure to meet the additional demand and new customer connections forecast over the forecast period;

growth related opex is the incremental annual cost of operating and maintaining the newly constructed network and connection assets over the forecast period;

incremental demand is the forecast change in kVA demand compared with the base year; and

PV stands for the present value of that calculation.

The calculated AIC values derived from our capital and operating forecasts along with other assumptions are shown in Table 17.18. These values are derived for each system level.

Table 17.18: AIC Calculations

System level	Δ MW	Δ cost	ST	HV bus	HV net	LV bus	LV net	Alloc. cost	$/kW/ year	pf	$/kVA / year
ST	**5.4**	**4.7**	0.1					**0.1**	$19	0.95	**$18**
HV bus	**5.2**	**6.8**	0.1	0.1				**0.2**	$48	0.90	**$43**
HV net	**13.0**	**3.5**	0.2	0.4	0.2			**0.8**	$63	0.90	**$56**
LV bus	**59.8**	**7.5**	1.1	1.7	0.9	2.0		**5.8**	$96	0.90	**$87**
LV net	**161.2**	**3.6**	3.1	4.6	2.4	5.4	3.6	**19.2**	$119	0.90	**$107**
Totals	**244.5**	***26.1***	***4.7***	***6.8***	***3.5***	***7.5***	***3.6***	***26.1***			

Source: SA Power Networks analysis

Note: Totals may not add due to rounding

Where:

ST	refers to sub-transmission lines level;
ZSN	refers to a zone substation level;
HV feeder	refers to the High Voltage feeder;
LV substation	refers to a Low Voltage substation; and
LV feeder	refers to the Low Voltage feeder;
Δ MW	refers to the change in MW (demand)
Δ cost	refers to the change in costs
ST	refers to the substation (as above)
HV bus	refers to the High Voltage bus at the zone substation
HV net	refers to the High Voltage feeder
LV bus	refers to the distribution transformers
LV net	refers to the LV network
Alloc. Cost	refers to the allocated cost
$/kW/ year	refers to the demand charge for measured kW each year
Pf	refers to the power factor for that class
$/kVA/ year	refers to the demand charge for measured kVA each year

The calculation of the AIC from the forecast kW demand is represented in $/kW/annum. The network is augmented to provide additional capacity represented in kVA for the connection of additional load, rather than in kW terms. Accordingly, the LRMC has been converted to $/kVA per annum using the typical (and compliant) power factor for each voltage level.

In Table 17.19 below, the LRMC outcomes have been calculated for individual tariff classes for 2020/21. The AIC results at the sub-transmission, high voltage and distribution transformer levels are directly applicable to the major business, high voltage business and large LV business tariff classes. At low voltage, the LRMC outcomes apply to both Small business and Residential tariff classes.

Table 17.19: Calculated LRMC for SA Power Networks' distribution network

Tariff class	LRMC, $/kVA per annum
Major Business – Sub-transmission	$18
Major Business – Zone substation	$43
Large HV business	$56
Large LV business Bus	$87
Small business Bus	$107
LV residential	$107

Clause 6.18.5(g) - Tariffs reflect total efficient costs

The way in which the LRMC and the balance of efficient costs has been taken into account by SA Power Networks in establishing the 2020-25 tariffs has involved the following considerations:

- ***Ensuring that demand price signalling components reasonably signal the LRMC:*** As discussed above.
- ***Use of price signalling components where practicable:*** In Type 6 metering situations where demand cannot be effectively signalled, energy rates have been structured to ensure that efficient costs are recovered. However, the metering does not indicate usage during high consumption periods, so we have retained relatively simple tariff structures which recover the efficient costs for that tariff's assigned customers.
- ***Revenue recovery through non-distortionary charging parameters:*** For cost-reflective tariffs, demand charging parameters recover a proportion of the total revenue reflecting high network utilisation period future costs. The balance of revenue recovery takes place in the least distortionary manner possible, through fixed supply charges for the efficient costs of local assets and customer service with the balance recovered through energy usage rates. Lower rates apply to usage that is outside of high network utilisation periods for off peak periods (two-rate tariffs) and controlled load.

Table 17.20 below outlines how SA Power Networks allocates the revenue across tariff classes. This ensures that tariffs reflect the efficient costs incurred in supplying customers using those tariffs. A few key points of explanation are set out below. Note Table 21 shows how the direct control services costs are allocated and it also shows the methods for recovery of Designated Pricing Proposal Charges under clause 6.18.7 of the Rules (Transmission charges) and of Jurisdictional Scheme Amounts under clause 6.18.7A (the solar FiT).

Table 17.20: 2020-21 revenue cost allocation across network elements and to tariff classes

<table>
<tr><th>Allocation basis to tariff class</th><th colspan="5">Tariff Classes</th></tr>
<tr><th></th><th>Major business</th><th>High Voltage business</th><th>Large LV business</th><th>Small business</th><th>Residential</th></tr>
<tr><td>Number of Customers (NMI's)</td><td>0.0%</td><td>0.0%</td><td>0.5%</td><td>10.7%</td><td>88.8%</td></tr>
<tr><td>Diversified Demand (MVA)</td><td>4.3%</td><td>5.3%</td><td>24.4%</td><td>18.4%</td><td>47.6%</td></tr>
<tr><td>Usage GWh (at Pool Exit)</td><td>10.5%</td><td>7.6%</td><td>29.0%</td><td>15.1%</td><td>36.8%</td></tr>
<tr><td>Distribution (SA Power Networks)</td><td colspan="5"></td></tr>
<tr><td>Sub-transmission lines</td><td colspan="5">8% allocated half demand and half usage</td></tr>
<tr><td>Zone substations</td><td colspan="5">17% allocated half demand and half usage</td></tr>
<tr><td>High Voltage Lines</td><td></td><td colspan="4">33% allocated half demand and half usage</td></tr>
<tr><td>Distribution transformers</td><td></td><td></td><td colspan="3">17% allocated half demand and half usage</td></tr>
<tr><td>Low voltage Lines</td><td></td><td></td><td></td><td colspan="2">15% to NMI/demand/usage</td></tr>
<tr><td>Services, GSLs</td><td></td><td></td><td></td><td colspan="2">6% NMIs only</td></tr>
<tr><td>Customer related</td><td colspan="5">3% customer related</td></tr>
<tr><td>PV FiT Recovery (SA Government Scheme)</td><td colspan="5"></td></tr>
<tr><td>PV FiT Recovery</td><td colspan="4">37% Allocated on DUoS proportion</td><td>63%</td></tr>
<tr><td>Transmission (ElectraNet)</td><td colspan="5"></td></tr>
<tr><td>Transmission exit</td><td rowspan="4">6% locational price pass through</td><td colspan="4">10% peak demand allocation</td></tr>
<tr><td>Transmission locational</td><td colspan="4">32% peak demand allocation</td></tr>
<tr><td>Transmission Non-locational</td><td colspan="2" rowspan="2">20% Demand</td><td colspan="2" rowspan="2">32% allocated on usage</td></tr>
<tr><td>Transmission Common Service</td></tr>
</table>

Table 17.21: 2020-21 revenue cost allocation to tariff classes ($nominal)

Allocation of forecast 2020/21 $ nominal	Tariff Classes					
	Major business	High Voltage business	Large LV business	Small business	Residential	Total
Distribution [1]	10.0	32.5	181.5	144.9	433.1	802.0
Transmission [2]	16.6	14.8	66.9	43.4	108.4	250.0
PV FiT [3]	0.8	2.6	14.6	11.6	50.4	80.0
Total [4]	**27.4**	**49.9**	**263.0**	**199.9**	**591.9**	**1,132.0**

Source: SA Power Networks analysis

Note:
1. Distribution represents the forecast smoothed revenue for 2020/21. Any Service Target Performance Incentive Scheme payment or adjustment for past over/under recovery would be incremental to this.
2. Transmission is an estimate. It could vary depending on the level of discount applied because of inter-regional settlements surpluses and payments from/to transmission interstate.
3. PV FiT is based on forecast payments on the 44 cents/kWh SA Government PV FiT Rebate.
4. Some totals may not add due to minor rounding variances.

Table 17.22: 2020-21 revenue cost allocation to tariff classes (% by tariff class)

Allocation of forecast 2020/21 % by tariff class	Tariff Classes					
	Major business	High Voltage business	Large LV business	Small business	Residential	Total
Distribution [1]	1.2%	4.0%	22.6%	18.1%	54.0%	100.0%
Transmission [2]	6.6%	5.9%	26.8%	17.3%	43.3%	100.0%
PV FiT [3]	1.0%	3.3%	18.2%	14.5%	63.0%	100.0%
Total [4]	**2.4%**	**4.4%**	**23.2%**	**17.7%**	**52.3%**	**100.0%**

Source: SA Power Networks analysis
See explanation of notes above.

Distribution Revenue of $802 million are allocated across the tariff classes (and the tariffs) according to the usage by customers of the various voltage steps (represented by asset categories) involved. The efficient costs are apportioned across these asset categories, with customers' use of these assets determined by the customers' diversified demand and usage. Some assets are apportioned according to customer numbers eg the connection services and a portion of the asset LV Lines reflecting house frontage needs. Customers are only charged for an asset category if they use it.

We allocate 50% of asset charges to demand as we have found that these amounts broadly reflect the LRMC of these assets. Note that we price the actual tariffs using the actual LRMC calculation, not the 50% cost allocation. The balance of asset charges is allocated in a non-distortionary manner using energy, apart from those costs which are driven principally by numbers of customers. If we need to consider pricing for a potentially constrained network, we will look at other variations to this for those specific locations and consider an 'opt-in' tariff/rebate. The variation might have a stronger demand signal reflecting the local LRMC. Customers would retain the right to access State-wide prices despite the constraint.

17.14.4 Cost allocation

Table 17.23: Cost allocation outcomes for 2020-21

2020-21 Forecast	Year ended 30 June					
	Major business	HV business	Large LV business	Small business	Residential	Total
$m						
Distribution	10.0	32.5	181.5	144.9	433.1	802.0
Transmission	16.6	14.8	66.9	43.4	108.4	250.0
PV FiT	0.8	2.6	14.6	11.6	50.4	80.0
Total NUoS	**27.4**	**49.9**	**263.0**	**199.9**	**591.9**	**1,132.0**
%						
Distribution	1.2%	4.0%	22.6%	18.1%	54.0%	100.0%
Transmission	6.6%	5.9%	26.8%	17.3%	43.3%	100.0%
PV FiT	1.0%	3.3%	18.2%	14.5%	63.0%	100.0%
Total NUos	**2.4%**	**4.4%**	**23.2%**	**17.7%**	**52.3%**	**100.0%**

Source: SA Power Networks analysis
Note, some totals may not add due to rounding.

Note that the demand applied in the allocation process is the relevant peak demand for each tariff, not the contribution to co-incident peak demand. This ensures that Business and Residential each pay a fair share of the relevant network costs to service the customers. If we used co-incident peak, then residential customer's investment in solar systems which has shifted the co-incident peak from the time of business peak to that of residential peak, would result in residential customers paying more post-investment in solar.

We need both a business network and a residential network. We also need a fair sharing of the costs of the higher voltages, which we achieve by using each tariff classes co-incident peak demand even though they may occur at a different time to each other. This is consistent with our past cost allocation practice (ie before solar investments).

We do provide signalling through peak price tariff elements (demand and ToU) for co-incident congestion, separate from cost allocation.

Percentage of cost allocation by tariff class for the 2020-21 forecast are in Table 17.24.

Table 17.24: Cost allocation proportions by tariff class 2020-21

2020-21 Forecast	Year ended 30 June					
	Major business	HV business	Large LV business	Small business	Residential	Total
%						
NMIs	0.0%	0.02%	0.5%	10.7%	88.7%	100.0%
Peak Demand	4.3%	5.3%	24.4%	18.3%	47.6%	100.0%
Energy	4.1%	3.7%	14.9%	22.2%	55.1%	100.0%

Source: SA Power Networks analysis
Note, some totals may not add due to rounding.

17.14.4.1 Residual distribution cost recovery

After pricing the LRMC signal in the DUoS demand tariff element, the balance of residual costs is recovered from usage and fixed (supply charge) tariff elements.

The residential supply charge has been set to recover the service wire cost and about half of the LV lines costs allocated to residential. Overall, the fixed charges (including PV-FiT recovery and transmission components) amount to 22.5% of the residential usage tariff NUoS[21] charges. This is in line with the recommendations of the Electricity Advisory Panel, a group established in 2016to run deliberative sessions on tariff recovery which supported up to 20% of residential charges being fixed (this concept was first adopted for the PV- FiT recovery. We have used the same concept for providing a fair and equitable limit to NUoS fixed charges).

The agreed demand tariffs for large LV business and HV business include some supply charges reflecting fixed costs associated with the connecting equipment (eg the transformer for LV agreed demand). Refer to Table 17.25, which shows the proportion of an average customers distribution charge, recovering either LRMC reflective costs (demand charges) or residual costs (fixed and usage charges). Note that the residential and small business usage tariffs do not have any significant LRMC demand tariff element.

Table 17.25: Residual distribution cost recovery 2020-21

Tariff element	Major business	HV business	Large LV business	Small business	Residential
LRMC Demand	70%	47%	41%	3%	-
Fixed Charges	10%	9%	7%	11%	28%
Usage Charges	20%	44%	52%	86% [1]	72%

Note 1. Small business ToU tariff charges 11% of distribution costs recovery from peak usage over the four-hour window for five months of the year. The supply charge is 8% of this tariff on average.

17.14.4.2 PV-FiT recovery

We discussed the relative level of PV-FiT recovery from different tariff classes at our deliberative session with our Electricity Advisory Panel in August 2016. The Panel decided that the proportion of costs borne by residential customers in 2016-17 (63%) was reasonable. The Panel also decided that 20% of the residential recovery should be on a 'per customer' basis with the balance recovered from usage.

In 2017-20, we have simplified the pricing of the PV-FiT recovery to a flat rate (c/kWh) with a single price set for each tariff class. The residential tariff class has 20% of the recovery priced on a $/customer basis and small business has a portion of their costs charged out at the same $/customer. This enables a similar spread across the tariff classes similar to the previous outcomes. Table 17.26 below shows the indicative prices for 2020-21 to recover $80M in PV-FiT recovery.

Table 17.26: FiT cost recovery

Tariff element	Major business	HV business	Large LV business	Small business	Small business unmetered	Residential	Controlled Load
Fixed Charges $pa	-	-	-	$13.00	-	$13.00	-
Usage Charges c/kWh	0.08	0.33	0.51	0.70	0.70	1.26	1.26

[21] *NUoS is the Network Use of System and includes the Distribution, Transmission and PV FiT recovery network charges*

17.14.4.3 Transmission Recovery

We apply the ElectraNet pricing structure where possible as our basis for allocating and pricing the recovery of Designated Pricing Proposal transmission charges under NER clause 6.18.7. For our Major Business tariff class, each customer is priced individually according to their location and their demand/energy characteristics. They receive the same transmission price as if they were directly connected to the transmission network. For all other tariff classes, we apply a State-wide average price but pass through the intent of ElectraNet's prices, for example:

- The locational charges for transmission exits and locational TUoS are summed and allocated evenly across all customers according to their diversified demand. Where we have demand components in our tariffs, these costs are reflected in that tariff parameter. Where we do not have demand components, these costs are included in the usage charges.

- The non-locational and common service charges are allocated to tariff classes according to the load factor of that tariff class. ElectraNet has a choice of price for these charges, with a maximum $/kW charge suitable for tariff classes with above-average load factor and a maximum $/MWh charge suitable for tariff classes with below average load factor. We allocate the demand tariffs classes on the $/kW basis (as these customers have above average load factor) with the charges recovered from a usage (c/kWh) basis that does not distort the TUoS demand signal. The balances of these costs are allocated to the usage based small customer tariff classes (as these have below average load factor) with the amounts split amongst the tariff classes according to energy usage. This results in a more optimal allocation of costs and resultant prices than if a combination of the ElectraNet $/MWh and $/kW options were used. It also more closely reflects the intent of ElectraNet's pricing structure.

The revenue cost allocation model enables us to reasonably apportion our charges across customers in a manner which ensures good cost-reflectivity for State-wide prices. It also provides guidance for the subsequent conversion of allocated costs to prices.

Clause 6.18.5(h) and (i) - Customer impact and understanding of tariffs

Clause 6.18.5(h) requires us to consider the impact on customers of annual changes in prices. This will mainly be an Annual Pricing Proposal matter however this clause has some relevance to the TSS.
We are required to balance the competing needs of having tariffs that comply with the pricing principles (ie are cost-reflective), the time necessary for a period of transition to such tariffs, the degree of customer choice available for tariffs and the extent to which customers can mitigate tariff impacts by responding through usage decisions. Clause 6.18.5(i) goes further to require us to structure our tariffs in a way that can be understood by that tariff's customers, with some consideration of information available to and consultation with those customers.

In the development of our TSS we have adopted a measured and methodical approach towards cost-reflective tariffs for residential customers and small business customers. In developing this TSS we have taken into consideration the additional findings from our recent stakeholder engagement outlined section 17.8.

SA Power Networks' 2020-25 tariffs as outlined in this TSS have therefore been structured to comply with the pricing principles of clauses 6.18.5 of the Rules.

Appendix A. Indicative Pricing Schedule Standard Control Services

The indicative prices for the five years of the 2020-25 RCP are set out in the pages below.

Table 17.27: Residential and Small business indicative prices

Residential and Small Business Indicative Prices 2020/21 and 2024/25, excl GST		2020/21				2021/22				2022/23				2023/24				2024/25			
		DUoS	TUoS	PV FiT	NUoS	DUoS	TUoS	PV FiT	NUoS	DUoS	TUoS	PV FiT	NUoS	DUoS	TUoS	PV FiT	NUoS	DUoS	TUoS	PV FiT	NUoS
Residential Customers																					
Residential Type 6	Tariff Closed																				
Customers/Supply Ch	$ pa	153.23	-	12.99	166.22	163.23	-	12.99	176.22	173.23	-	12.99	186.22	183.23	-	12.99	196.22	193.23	-	12.99	206.22
Usage	$/kWh	0.0973	0.0340	0.0126	0.1438	0.0969	0.0346	0.0124	0.1439	0.0969	0.0352	0.0123	0.1445	0.0971	0.0360	0.0123	0.1453	0.0965	0.0364	0.0121	0.1451
Residential TOU	Default Tariff, Type 4 and 5 meters																				
Customers/Supply Ch	$ pa	153.23	-	12.99	166.22	163.23	-	12.99	176.22	173.23	-	12.99	186.22	183.23	-	12.99	196.22	193.23	-	12.99	206.22
Peak Usage	$/kWh	0.1216	0.0425	0.0157	0.1798	0.1212	0.0432	0.0155	0.1799	0.1211	0.0441	0.0154	0.1806	0.1213	0.0450	0.0154	0.1817	0.1206	0.0455	0.0151	0.1813
Off-Pk Usage	$/kWh	0.0486	0.0170	0.0063	0.0719	0.0485	0.0173	0.0062	0.0720	0.0485	0.0176	0.0062	0.0723	0.0485	0.0180	0.0061	0.0727	0.0483	0.0182	0.0061	0.0725
Solar Sponge Usage	$/kWh	0.0243	0.0085	0.0031	0.0360	0.0242	0.0086	0.0031	0.0360	0.0242	0.0088	0.0031	0.0361	0.0243	0.0090	0.0031	0.0363	0.0241	0.0091	0.0030	0.0363
Residential Prosumer	Opt-in Tariff, Type 4 meters																				
Customers/Supply Ch	$ pa	153.23	-	12.99	166.22	163.23	-	12.99	176.22	173.23	-	12.99	186.22	183.23	-	12.99	196.22	193.23	-	12.99	206.22
Peak Usage	$/kWh	0.0608	0.0255	0.0157	0.1020	0.0606	0.0259	0.0155	0.1021	0.0606	0.0264	0.0154	0.1024	0.0607	0.0270	0.0154	0.1030	0.0603	0.0273	0.0151	0.1028
Off-Pk Usage	$/kWh	0.0243	0.0102	0.0063	0.0408	0.0242	0.0104	0.0062	0.0408	0.0242	0.0106	0.0062	0.0410	0.0243	0.0108	0.0061	0.0412	0.0241	0.0109	0.0061	0.0411
Solar Sponge Usage	$/kWh	0.0122	0.0051	0.0031	0.0204	0.0121	0.0052	0.0031	0.0204	0.0121	0.0053	0.0031	0.0205	0.0121	0.0054	0.0031	0.0206	0.0121	0.0055	0.0030	0.0206
Summer Demand	3 $/kW pa	80.00	30.00	-	110.00	79.72	30.51	-	110.23	79.72	31.10	-	110.82	79.85	31.75	-	111.59	79.39	32.15	-	111.53
OPCL Hot Water Type 5, 6	Tariff Closed																				
Usage	$/kWh	0.0486	0.0170	0.0063	0.0719	0.0485	0.0173	0.0062	0.0720	0.0485	0.0176	0.0062	0.0723	0.0485	0.0180	0.0061	0.0727	0.0483	0.0182	0.0061	0.0725
OPCL Hot Water Type 4	Default Tariff, Type 4 meters OPCL																				
Peak Usage	$/kWh	0.1216	0.0425	0.0157	0.1798	0.1212	0.0432	0.0155	0.1799	0.1211	0.0441	0.0154	0.1806	0.1213	0.0450	0.0154	0.1817	0.1206	0.0455	0.0151	0.1813
Off-Pk Usage	$/kWh	0.0486	0.0170	0.0063	0.0719	0.0485	0.0173	0.0062	0.0720	0.0485	0.0176	0.0062	0.0723	0.0485	0.0180	0.0061	0.0727	0.0483	0.0182	0.0061	0.0725
Solar Sponge Usage	$/kWh	0.0243	0.0085	0.0031	0.0360	0.0242	0.0086	0.0031	0.0360	0.0242	0.0088	0.0031	0.0361	0.0243	0.0090	0.0031	0.0363	0.0241	0.0091	0.0030	0.0363
Small Business Customers																					
Business Single Type 6	Tariff Closed																				
Customers/Supply Ch	$ pa	173.23	-	13.10	186.33	193.23	-	13.10	206.33	213.23	-	13.10	226.33	233.23	-	13.10	246.33	253.23	-	13.10	266.33
Usage	$/kWh	0.0961	0.0330	0.0070	0.1360	0.0973	0.0338	0.0069	0.1381	0.0987	0.0347	0.0069	0.1404	0.0996	0.0354	0.0069	0.1419	0.1003	0.0361	0.0068	0.1432
Business 2-Rate	Tariff Closed																				
Customers/Supply Ch	$ pa	173.23	-	13.10	186.33	193.23	-	13.10	206.33	213.23	-	13.10	226.33	233.23	-	13.10	246.33	253.23	-	13.10	266.33
Peak usage	$/kWh	0.1082	0.0371	0.0070	0.1523	0.1097	0.0381	0.0069	0.1548	0.1112	0.0391	0.0069	0.1573	0.1122	0.0399	0.0069	0.1590	0.1130	0.0407	0.0068	0.1605
Off-Pk Usage	$/kWh	0.0541	0.0186	0.0070	0.0796	0.0548	0.0191	0.0069	0.0809	0.0556	0.0196	0.0069	0.0821	0.0561	0.0200	0.0069	0.0829	0.0565	0.0203	0.0068	0.0836
Business TOU	Default Tariff <70 kVA demand (incl all Whole Current meters), Type 4 and 5 meters																				
Customers/Supply Ch	$ pa	173.23	-	13.10	186.33	193.23	-	13.10	206.33	213.23	-	13.10	226.33	233.23	-	13.10	246.33	253.23	-	13.10	266.33
Peak usage	$/kWh	0.1431	0.0491	0.0070	0.1992	0.1450	0.0504	0.0069	0.2024	0.1470	0.0518	0.0069	0.2057	0.1484	0.0528	0.0069	0.2080	0.1494	0.0538	0.0068	0.2100
Shoulder Usage	$/kWh	0.1009	0.0346	0.0070	0.1424	0.1022	0.0355	0.0069	0.1447	0.1036	0.0365	0.0069	0.1470	0.1045	0.0372	0.0069	0.1486	0.1053	0.0379	0.0068	0.1500
Off-Peak Usage	$/kWh	0.0576	0.0198	0.0070	0.0844	0.0584	0.0203	0.0069	0.0857	0.0592	0.0208	0.0069	0.0870	0.0597	0.0213	0.0069	0.0879	0.0602	0.0217	0.0068	0.0886
Business TOU+MD >70 kVA	Default Tariff >70 kVA demand, type 4 and 5 meters, Opt-in <70 kVA																				
Customers/Supply Ch	$ pa	173.23	0.02	13.10	186.35	193.23	0.02	13.10	206.35	213.23	0.02	13.10	226.35	233.23	0.02	13.10	246.35	253.23	0.02	13.10	266.35
Anytime Max Demand	3 $/kVA pa	16.07	-	-	16.07	16.47	-	-	16.47	16.88	-	-	16.88	17.30	-	-	17.30	17.74	-	-	17.74
Peak usage	$/kWh	0.1431	0.0491	0.0070	0.1992	0.1450	0.0504	0.0069	0.2024	0.1470	0.0518	0.0069	0.2057	0.1484	0.0528	0.0069	0.2080	0.1494	0.0538	0.0068	0.2100
Shoulder Usage	$/kWh	0.0893	0.0307	0.0070	0.1269	0.0905	0.0315	0.0069	0.1289	0.0918	0.0323	0.0069	0.1310	0.0926	0.0330	0.0069	0.1324	0.0933	0.0336	0.0068	0.1336
Off-Peak Usage	$/kWh	0.0499	0.0171	0.0070	0.0740	0.0506	0.0176	0.0069	0.0752	0.0513	0.0181	0.0069	0.0763	0.0518	0.0184	0.0069	0.0771	0.0521	0.0188	0.0068	0.0777
Small Business Actual Demand	Tariff Closed																				
Customers/Supply Ch	$ pa	173.23	-	13.10	186.33	193.23	-	13.10	206.33	213.23	-	13.10	226.33	-	-	-	-	-	-	-	-
Peak Actual Demand	1 $/kVA/mth pa	8.90	2.53	-	11.43	9.12	2.59	-	11.71	9.35	2.65	-	12.01	-	-	-	-	-	-	-	-
Shoulder Actual Demand	2 $/kVA/mth pa	4.45	1.27	-	5.72	4.56	1.30	-	5.87	4.68	1.34	-	6.01	-	-	-	-	-	-	-	-
Usage	$/kWh	0.0504	0.0195	0.0070	0.0769	0.0576	0.0223	0.0069	0.0868	0.0648	0.0251	0.0069	0.0968	-	-	-	-	-	-	-	-
Small Business OPCL Type 5, 6	Tariff Closed. Not available with type 4 meters																				
Usage	$/kWh	0.0486	0.0170	0.0070	0.0726	0.0485	0.0173	0.0069	0.0727	0.0485	0.0176	0.0069	0.0730	0.0485	0.0180	0.0069	0.0734	0.0483	0.0182	0.0068	0.0733

Notes on Demand Elements

1 highest daily demand each of five months Nov-March charged per month
2 highest daily demand each of twelve months July-June charged per month
3 12 month rolling reset charged proportionally each month
4 agreed demand charged proportionally each month
5 Peak demand not applicable to backup, incurred by principal supply

Table 17.28: Large LV business indicative prices

Large LV Business Indicative Prices		2020/21				2020/21				2020/21				2020/21				2024/25			
2020/21 and 2024/25, excl GST		DUoS	TUoS	PV FiT	NUoS	DUoS	TUoS	PV FiT	NUoS	DUoS	TUoS	PV FiT	NUoS	DUoS	TUoS	PV FiT	NUoS	DUoS	TUoS	PV FiT	NUoS
Large LV Business Customers																					
Large LV Bus Actual Demand	Tariff Closed																				
Customers/Supply Ch	$ pa	173.23	-	-	173.23	193.23	-	-	193.23	213.23	-	-	213.23	-	-	-	-	-	-	-	-
Peak Actual Demand	1 $/kVA/mth pa	8.90	2.53	-	11.43	9.12	2.59	-	11.71	9.35	2.65	-	12.01	-	-	-	-	-	-	-	-
Shoulder Actual Demand	2 $/kVA/mth pa	4.45	1.27	-	5.72	4.56	1.30	-	5.87	4.68	1.34	-	6.01	-	-	-	-	-	-	-	-
Usage	$/kWh	0.0504	0.0195	0.0051	0.0750	0.0576	0.0223	0.0051	0.0850	0.0648	0.0251	0.0051	0.0950	-	-	-	-	-	-	-	-
Large Bus Monthly Demand	Opt-In Tariff, Same prices apply to CBD and Rest of SA, Peak demand period differs																				
Customers/Supply Ch	$ pa	2,076	-	-	2,076	2,128	-	-	2,128	2,181	-	-	2,181	2,236	-	-	2,236	2,292	-	-	2,292
Peak Actual Monthly Dem	1 $/kVA/mth pa	10.26	5.91	-	16.16	10.51	6.05	-	16.57	10.77	6.20	-	16.98	11.04	6.36	-	17.40	11.32	6.52	-	17.84
Anytime Actual Demand	3 $/kVA pa	44.34	-	-	44.34	45.45	-	-	45.45	46.59	-	-	46.59	47.75	-	-	47.75	48.95	-	-	48.95
Peak Usage	$/kVA pa	0.0371	0.0197	0.0051	0.0618	0.0381	0.0202	0.0051	0.0634	0.0389	0.0207	0.0051	0.0647	0.0394	0.0210	0.0050	0.0654	0.0397	0.0212	0.0050	0.0659
Off-Peak Usage	$/kWh	0.0278	0.0148	0.0051	0.0476	0.0286	0.0151	0.0051	0.0488	0.0292	0.0155	0.0051	0.0498	0.0296	0.0157	0.0050	0.0503	0.0298	0.0159	0.0050	0.0507
Large Bus Annual Demand	Default Tariff, Same prices apply to CBD and Rest of SA, Peak demand period differs																				
Customers/Supply Ch	$ pa	2,076	-	-	2,076	2,128	-	-	2,128	2,181	-	-	2,181	2,236	-	-	2,236	2,292	-	-	2,292
Peak Annual Max Demand	3 $/kVA pa	41.02	23.62	-	64.64	42.05	24.21	-	66.26	43.10	24.82	-	67.92	44.18	25.44	-	69.61	45.28	26.07	-	71.36
Anytime Actual Demand	3 $/kVA pa	44.34	-	-	44.34	45.45	-	-	45.45	46.59	-	-	46.59	47.75	-	-	47.75	48.95	-	-	48.95
Peak Usage	$/kWh	0.0371	0.0197	0.0051	0.0618	0.0381	0.0202	0.0051	0.0634	0.0389	0.0207	0.0051	0.0647	0.0394	0.0210	0.0050	0.0654	0.0397	0.0212	0.0050	0.0659
Off-Peak Usage	$/kWh	0.0278	0.0148	0.0051	0.0476	0.0286	0.0151	0.0051	0.0488	0.0292	0.0155	0.0051	0.0498	0.0296	0.0157	0.0050	0.0503	0.0298	0.0159	0.0050	0.0507
Large Bus Annual >1000 kVA	Opt-In Tariff, Same prices apply to CBD and Rest of SA, Peak demand period differs																				
Customers/Supply Ch	$ pa	23,408	-	-	23,408	23,993	-	-	23,993	24,593	-	-	24,593	25,208	-	-	25,208	25,838	-	-	25,838
Peak Annual Max Demand	3 $/kVA pa	41.02	23.62	-	64.64	42.05	24.21	-	66.26	43.10	24.82	-	67.92	44.18	25.44	-	69.61	45.28	26.07	-	71.36
Anytime Actual Demand	3 $/kVA pa	23.01	-	-	23.01	23.59	-	-	23.59	24.18	-	-	24.18	24.78	-	-	24.78	25.40	-	-	25.40
Peak Usage	$/kWh	0.0371	0.0197	0.0051	0.0618	0.0381	0.0202	0.0051	0.0634	0.0389	0.0207	0.0051	0.0647	0.0394	0.0210	0.0050	0.0654	0.0397	0.0212	0.0050	0.0659
Off-Peak Usage	$/kWh	0.0278	0.0148	0.0051	0.0476	0.0286	0.0151	0.0051	0.0488	0.0292	0.0155	0.0051	0.0498	0.0296	0.0157	0.0050	0.0503	0.0298	0.0159	0.0050	0.0507
Large Bus Back-Up	Special Tariff																				
Customers/Supply Ch	$ pa	2,076	-	-	2,076	2,128	-	-	2,128	2,181	-	-	2,181	2,236	-	-	2,236	2,292	-	-	2,292
Peak Annual Max Demand	5 $/kVA pa																				
Anytime Actual Demand	4 $/kVA pa	44.34	-	-	44.34	45.45	-	-	45.45	46.59	-	-	46.59	47.75	-	-	47.75	48.95	-	-	48.95
Peak Usage	$/kWh	0.0371	0.0197	0.0051	0.0618	0.0381	0.0202	0.0051	0.0634	0.0389	0.0207	0.0051	0.0647	0.0394	0.0210	0.0050	0.0654	0.0397	0.0212	0.0050	0.0659
Off-Peak Usage	$/kWh	0.0278	0.0148	0.0051	0.0476	0.0286	0.0151	0.0051	0.0488	0.0292	0.0155	0.0051	0.0498	0.0296	0.0157	0.0050	0.0503	0.0298	0.0159	0.0050	0.0507
Large Bus Generation Supplies	Special Tariff																				
Customers/Supply Ch	$ pa	2,076	-	-	2,076	2,128	-	-	2,128	2,181	-	-	2,181	2,236	-	-	2,236	2,292	-	-	2,292
Peak Annual Max Demand	4 $/kVA pa	41.02	23.62	-	64.64	42.05	24.21	-	66.26	43.10	24.82	-	67.92	44.18	25.44	-	69.61	45.28	26.07	-	71.36
Anytime Actual Demand	4 $/kVA pa	44.34	-	-	44.34	45.45	-	-	45.45	46.59	-	-	46.59	47.75	-	-	47.75	48.95	-	-	48.95
Peak Usage	$/kWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Off-Peak Usage	$/kWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Bus Trans Type 6 Single	Closed																				
Customers/Supply Ch	$ pa	173.23	-	-	173.23	193.23	-	-	193.23	213.23	-	-	213.23	233.23	-	-	233.23	253.23	-	-	253.23
Usage	$/kWh	0.1153	0.0396	0.0051	0.1599	0.1168	0.0406	0.0051	0.1625	0.1184	0.0417	0.0051	0.1652	0.1195	0.0425	-	0.1620	0.1203	0.0433	-	0.1636
Large Bus Trans Type 6 2-rate	Closed																				
Customers/Supply Ch	$ pa	173.23	-	-	173.23	193.23	-	-	193.23	213.23	-	-	213.23	233.23	-	-	233.23	253.23	-	-	253.23
Peak usage	$/kWh	0.1299	0.0446	0.0051	0.1795	0.1316	0.0458	0.0051	0.1824	0.1334	0.0470	0.0051	0.1855	0.1346	0.0479	-	0.1826	0.1356	0.0488	-	0.1844
Off-Pk Usage	$/kWh	0.0649	0.0223	0.0051	0.0923	0.0658	0.0229	0.0051	0.0938	0.0667	0.0235	0.0051	0.0953	0.0673	0.0240	-	0.0913	0.0678	0.0244	-	0.0922

Notes on Demand Elements

1 highest daily demand each of five months Nov-March charged per month
2 highest daily demand each of twelve months July-June charged per month
3 12 month rolling reset charged proportionally each month
4 agreed demand charged proportionally each month
5 Peak demand not applicable to backup, incurred by principal supply

Table 17.29: Large HV business and Major business indicative prices

HV and Major Business Indicative Prices 2020/21 and 2024/25, excl GST		2020/21 DUoS	TUoS	PV FiT	NUoS	2020/21 DUoS	TUoS	PV FiT	NUoS	2020/21 DUoS	TUoS	PV FiT	NUoS	2020/21 DUoS	TUoS	PV FiT	NUoS	2024/25 DUoS	TUoS	PV FiT	NUoS
HV Business Customers																					
HV Business Actual Demand	Tariff Closed																				
Customers/Supply Ch	$ pa	173.23	-	-	173.23	193.23	-	-	193.23	213.23	-	-	213.23	-	-	-	-	-	-	-	-
Peak Actual Demand	1 $/kVA/mth pa	44.50	12.63	-	57.13	45.62	12.95	-	58.56	46.76	13.27	-	60.03	-	-	-	-	-	-	-	-
Shoulder Actual Demand	2 $/kVA/mth pa	53.43	15.26	-	68.69	54.76	15.65	-	70.41	56.13	16.04	-	72.17	-	-	-	-	-	-	-	-
Usage	$/kWh	0.0504	0.0195	0.0033	0.0732	0.0576	0.0223	0.0033	0.0832	0.0648	0.0251	0.0033	0.0932	-	-	-	-	-	-	-	-
HV Business Monthly Demand	Opt-In Tariff, Same prices apply to CBD and Rest of SA, Peak demand period differs																				
Customers/Supply Ch	$ pa	14,220	-	-	14,220	14,575	-	-	14,575	14,940	-	-	14,940	15,313	-	-	15,313	15,696	-	-	15,696
Peak Actual Monthly Dem	1 $/kVA/mth pa	22.66	29.53	-	52.18	23.22	30.27	-	53.49	23.81	31.02	-	54.83	24.40	31.80	-	56.20	25.01	32.59	-	57.60
Anytime Actual Demand	3 $/kVA pa	44.34	-	-	44.34	45.45	-	-	45.45	46.59	-	-	46.59	47.75	-	-	47.75	48.95	-	-	48.95
Peak Usage	$/kVA pa	0.0207	0.0154	0.0033	0.0394	0.0211	0.0158	0.0033	0.0402	0.0215	0.0161	0.0033	0.0410	0.0217	0.0163	0.0033	0.0413	0.0218	0.0165	0.0033	0.0416
Off-Peak Usage	$/kWh	0.0155	0.0115	0.0033	0.0304	0.0158	0.0118	0.0033	0.0310	0.0161	0.0121	0.0033	0.0315	0.0163	0.0122	0.0033	0.0318	0.0164	0.0124	0.0033	0.0320
HV Business Annual Demand	Default Tariff, Same prices apply to CBD and Rest of SA, Peak demand period differs																				
Customers/Supply Ch	$ pa	14,220	-	-	14,220	14,575	-	-	14,575	14,940	-	-	14,940	15,313	-	-	15,313	15,696	-	-	15,696
Peak Annual Max Demand	3 $/kVA pa	18.13	23.62	-	41.75	18.58	24.21	-	42.79	19.04	24.82	-	43.86	19.52	25.44	-	44.96	20.01	26.07	-	46.08
Anytime Actual Demand	3 $/kVA pa	44.34	-	-	44.34	45.45	-	-	45.45	46.59	-	-	46.59	47.75	-	-	47.75	48.95	-	-	48.95
Peak Usage	$/kWh	0.0207	0.0154	0.0033	0.0394	0.0211	0.0158	0.0033	0.0402	0.0215	0.0161	0.0033	0.0410	0.0217	0.0163	0.0033	0.0413	0.0218	0.0165	0.0033	0.0416
Off-Peak Usage	$/kWh	0.0155	0.0115	0.0033	0.0304	0.0158	0.0118	0.0033	0.0310	0.0161	0.0121	0.0033	0.0315	0.0163	0.0122	0.0033	0.0318	0.0164	0.0124	0.0033	0.0320
HV Business Annual <500	Opt-In Tariff, Same prices apply to CBD and Rest of SA, Peak demand period differs																				
Customers/Supply Ch	$ pa	2,076	-	-	2,076	2,128	-	-	2,128	2,181	-	-	2,181	2,236	-	-	2,236	2,292	-	-	2,292
Peak Annual Max Demand	3 $/kVA pa	51.28	29.53	-	80.81	52.56	30.27	-	82.83	53.87	31.02	-	84.90	55.22	31.80	-	87.02	56.60	32.59	-	89.19
Anytime Actual Demand	3 $/kVA pa	44.34	-	-	44.34	45.45	-	-	45.45	46.59	-	-	46.59	47.75	-	-	47.75	48.95	-	-	48.95
Peak Usage	$/kWh	0.0371	0.0197	0.0033	0.0601	0.0381	0.0202	0.0033	0.0616	0.0389	0.0207	0.0033	0.0629	0.0394	0.0210	0.0033	0.0637	0.0397	0.0212	0.0033	0.0642
Off-Peak Usage	$/kWh	0.0278	0.0148	0.0033	0.0459	0.0286	0.0151	0.0033	0.0471	0.0292	0.0155	0.0033	0.0480	0.0296	0.0157	0.0033	0.0486	0.0298	0.0159	0.0033	0.0490
HV Business Back-Up	Special Tariff																				
Customers/Supply Ch	$ pa	14,220	-	-	14,220	14,575	-	-	14,575	14,940	-	-	14,940	15,313	-	-	15,313	15,696	-	-	15,696
Peak Annual Max Demand	5 $/kVA pa																				
Anytime Actual Demand	4 $/kVA pa	44.34	-	-	44.34	45.45	-	-	45.45	46.59	-	-	46.59	47.75	-	-	47.75	48.95	-	-	48.95
Peak Usage	$/kWh	0.0207	0.0154	0.0033	0.0394	0.0211	0.0158	0.0033	0.0402	0.0215	0.0161	0.0033	0.0410	0.0217	0.0163	0.0033	0.0413	0.0218	0.0165	0.0033	0.0416
Off-Peak Usage	$/kWh	0.0155	0.0115	0.0033	0.0304	0.0158	0.0118	0.0033	0.0310	0.0161	0.0121	0.0033	0.0315	0.0163	0.0122	0.0033	0.0318	0.0164	0.0124	0.0033	0.0320
HV Bus Generation Supplies	Special Tariff																				
Customers/Supply Ch	$ pa	14,220	-	-	14,220	14,575	-	-	14,575	14,940	-	-	14,940	15,313	-	-	15,313	15,696	-	-	15,696
Peak Annual Max Demand	4 $/kVA pa	18.13	23.62	-	41.75	18.58	24.21	-	42.79	19.04	24.82	-	43.86	19.52	25.44	-	44.96	20.01	26.07	-	46.08
Anytime Actual Demand	4 $/kVA pa	44.34	-	-	44.34	45.45	-	-	45.45	46.59	-	-	46.59	47.75	-	-	47.75	48.95	-	-	48.95
Peak Usage	$/kWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Off-Peak Usage	$/kWh	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Major Business Customers																					
Zone S-Stn Non-Loc	Tariff amended for individual Customers, eg TUoS and some DUoS fixed charges																				
Customers/Supply Ch	$ pa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Agreed Demand	4 $/kVA pa	-	23.62	-	23.62	-	24.21	-	24.21	-	24.82	-	24.82	-	25.44	-	25.44	-	26.07	-	26.07
Anytime Agreed Demand	4 $/kVA pa	41.02	-	-	41.02	42.05	-	-	42.05	43.10	-	-	43.10	44.18	-	-	44.18	45.28	-	-	45.28
Usage	$/kWh	0.0031	0.0111	0.0008	0.0150	0.0032	0.0114	0.0008	0.0153	0.0033	0.0117	0.0008	0.0157	0.0033	0.0119	0.0008	0.0160	0.0034	0.0122	0.0008	0.0164
Sub-Trans Non-Loc	Tariff amended for individual Customers, eg TUoS and some DUoS fixed charges																				
Customers/Supply Ch	$ pa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Peak Agreed Demand	4 $/kVA pa	-	18.16	-	18.16	-	18.62	-	18.62	-	19.08	-	19.08	-	19.56	-	19.56	-	20.05	-	20.05
Anytime Agreed Demand	4 $/kVA pa	9.31	5.46	-	14.77	9.54	5.59	-	15.14	9.78	5.73	-	15.52	10.03	5.88	-	15.90	10.28	6.02	-	16.30
Usage	$/kWh	0.0008	0.0111	0.0008	0.0126	0.0008	0.0114	0.0008	0.0129	0.0008	0.0117	0.0008	0.0132	0.0008	0.0119	0.0008	0.0135	0.0008	0.0122	0.0008	0.0138

Notes on Demand Elements

1 highest daily demand each of five months Nov-March charged per month
2 highest daily demand each of twelve months July-June charged per month
3 12 month rolling reset charged proportionally each month
4 agreed demand charged proportionally each month
5 Peak demand not applicable to backup, incurred by principal supply

Appendix B. Compliance Statement

The development of a Tariff Structure Statement for the 2020-25 Regulatory Control Period is governed by the Chapter 6 of Rules. The compliance statement shown in Table 17.30 has been prepared with reference to Version 117 of the Rules (20 December 2018).

Table 17.30: Compliance with the NER

Rule provision	Rule requirement	Relevant section
Part E: Proposed tariff structure statement		
6.8.2	**Submission of regulatory proposal and tariff structure statement**	
6.8.2(a)	A *Distribution Network Service Provider* must, whenever required to do so under paragraph (b), submit to the *AER* a proposed *tariff structure statement* related to the *distribution services* provided by means of, or in connection with, the *Distribution Network Service Provider's distribution system*.	Noted
6.8.2(c)(7) 6.8.2(c1) 6.8.2(c2) 6.8.2(d)	A regulatory proposal must include 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).	TSS, Sections 17.3 to 17.14
6.8.2(d1)	The proposed *tariff structure statement* must be accompanied by an *indicative pricing schedule*.	TSS Section 17.10 and Appendix A
6.8.2(d2)	The proposed *tariff structure statement* must comply with the pricing principles for *direct control services*.	TSS, Sections 17.3 to 17.14
Part I: Distribution Pricing Rules		
6.18.1A	**Tariff structure statement**	
6.18.1A(a)	A *tariff structure statement* of a *Distribution Network Service Provider* must include the following elements:	
6.18.1A(a)(1)	the *tariff classes* into which *retail customers* for *direct control services* will be divided during the relevant *regulatory control period*;	TSS Section 17.9
6.18.1A(a)(2)	the policies and procedures the *Distribution Network Service Provider* will apply for assigning *retail customers* to tariffs or reassigning *retail customers* from one tariff to another (including any applicable restrictions);	TSS Section 0
6.18.1A(a)(3)	the structures for each proposed tariff;	TSS Section 17.10
6.18.1A(a)(4)	the *charging parameters* for each proposed tariff; and	TSS Section 17.10
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.	TSS, Sections 17.14
6.18.1A(b)	A *tariff structure statement* must comply with the *pricing principles* for *direct control services*.	TSS, Sections 17.3 to 17.14
6.18.1A(c)	A *Distribution Network Service Provider* must comply with the *tariff structure statement* approved by the *AER* and any other applicable requirements in the *Rules*, when the provider is setting the prices that may be charged for *direct control services*.	Noted

Rule provision	Rule requirement	Relevant section
6.18.1A(d)	Subject to clause 6.18.1B, a *tariff structure statement* may not be amended during a *regulatory control period*. Note: Rule 6.13 still applies in relation to a *tariff structure statement* because that rule deals with the revocation and substitution of a distribution determination (which includes a *tariff structure statement*) as opposed to its amendment.	Noted
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*.	TSS Appendix A
6.18.3	**Tariff classes**	
6.18.3(b)	Each *retail* customer for *direct control services* must be a member of 1 or more *tariff classes*.	TSS Section 0
6.18.3(c)	Separate *tariff classes* must be constituted for *retail customers* to whom *standard control services* are supplied and *retail customers* to whom *alternative control services* are supplied (but a *retail customer* for both *standard control services* and *alternative control services* may be a member of 2 or more *tariff classes*).	TSS Section 17.10
6.18.3(d)	A *tariff class* must be constituted with regard to:	
6.18.3(d)(1)	the need to group *retail customers* together on an economically efficient basis; and	TSS Section 17.10, and 17.14
6.18.3(d)(2)	the need to avoid unnecessary transaction costs.	TSS Section 17.10, and 17.14
6.18.4	**Principles governing assignment or re-assignment of retail customers to tariff classes and assessment and review of basis of charging**	
6.18.4(a)	In formulating provisions of a distribution determination governing the assignment of *retail customers* to *tariff classes* or the re-assignment of *retail customers* from one *tariff class* to another, the *AER* must have regard to the following principles:	Noted
6.18.4(a)(1)	*retail customers* should be assigned to *tariff classes* on the basis of one or more of the following factors: (i) the nature and extent of their usage; (ii) the nature of their *connection* to the *network*; (iii) whether remotely-read interval metering or other similar metering technology has been installed at the *retail customer's* premises as a result of a *regulatory obligation or requirement*;	TSS Section 0
6.18.4(a)(2)	*retail customers* with a similar *connection* and usage profile should be treated on an equal basis;	TSS section 17.11.2
6.18.4(a)(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*;*	TSS section 0,
6.18.4(a)(4)	a *Distribution Network Service Provider's* decision to assign a customer to a particular *tariff class*, or to re-assign a customer from one *tariff class* to another should be subject to an effective system of assessment and review.	TSS section 17.11.2,
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.	Noted
6.18.5	**Pricing principles**	
Network pricing objective		
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*	Noted

Rule provision	Rule requirement	Relevant section
	to a *retail customer* should reflect the *Distribution Network Service Provider's* efficient costs of providing those services to *the retail customer*.	
Application of the pricing principles		
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).	Noted
6.18.5(c)	A *Distribution Network Service Provider's* tariffs may vary from tariffs which would result from complying with the pricing principles set out in paragraphs (e) to (g) only:	Noted
6.18.5(c)(1)	to the extent permitted under paragraph (h); and	Noted
6.18.5(c)(2)	to the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).	Noted
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*.	Noted
Pricing principles		
6.18.5(e)	For each *tariff class*, the revenue expected to be recovered must lie on or between:	
6.18.5(e)(1)	an upper bound representing the stand alone cost of serving the *retail customers* who belong to that class; and	TSS Section 17.14
6.18.5(e)(2)	a lower bound representing the avoidable cost of not serving those *retail customers*.	TSS Section 17.14
6.18.5(f)	Each tariff must be based on the *long run marginal cost* of providing the service to which it relates to the *retail customers* assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:	TSS Section 17.14
6.18.5(f)(1)	the costs and benefits associated with calculating, implementing and applying that method as proposed;	TSS Section 17.14
6.18.5(f)(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	TSS Section 17.14
6.18.5(f)(3)	the location of *retail customers* that are assigned to that tariff and the extent to which costs vary between different locations in the *distribution network*.	TSS Section 17.14
6.18.5(g)	The revenue expected to be recovered from each tariff must:	
6.18.5(g)(1)	reflect the *Distribution Network Service Provider's* total efficient costs of serving the *retail customers* that are assigned to that tariff;	TSS Section 17.14
6.18.5(g)(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	TSS Section 17.14
6.18.5(g)(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).	TSS Section 17.14
6.18.5(h)	A *Distribution Network Service Provider* must consider the impact on *retail customers* of changes in tariffs from the previous *regulatory year* and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the *Distribution Network Service Provider* considers reasonably necessary having regard to:	TSS Section 17.10
6.18.5(h)(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*);	TSS Section 17.14
6.18.5(h)(2)	the extent to which *retail customers* can choose the tariff to which they are assigned; and	TSS Section 0
6.18.5(h)(3)	the extent to which *retail customers* are able to mitigate the impact of changes in tariffs through their usage decisions.	TSS Section 0

Rule provision	Rule requirement	Relevant section
6.18.5(i)	The structure of each tariff must be reasonably capable of being understood by *retail customers* that are assigned to that tariff, having regard to:	TSS Section 17.10
6.18.5(i)(1)	the type and nature of those *retail customers*; and	TSS Section 17.8
6.18.5(i)(2)	the information provided to, and the consultation undertaken with, those *retail customers*.	TSS Section 17.8 and 17.10
6.18.5(j)	A tariff must comply with the *Rules* and all *applicable regulatory instruments*.	Noted
6.18.6	**Side constraints on tariffs for standard control services**	
6.18.6(a)	This clause applies only to *tariff classes* related to the provision of *standard control services*.	TSS Section 17.10
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.	TSS Section 17.14

Appendix C. Peak demand window identification

C.1 Introduction

In this appendix, we consider how the network is used at different times of the day, different days of the week, and across different sub-regions in the state, to determine if the observed differences are significant, and if there is a need to price the consumption of the network differently across the time and locational segments identified.

These matters need to be considered within the principles identified in Section 17.5 and we will test any conclusions against these principles in the discussion that follows.

C.2 Matters influencing the peak demand window in South Australia

C.2.1 Background – the recent past

Different customers make use of the network at different times, and to varying degrees. Network tariffs have traditionally been designed to recognise different users of the network and the degree to which they 'consume' the network. For example, large industrial customers use only the high voltage components of the network, whilst residential customers use most components of the network down to and including the low voltage transformers in the street. Some customers have high air-conditioning loads, and some have solar and export to the network during the solar peak but take power at other times. Some consumers use the majority of their power only on work days whilst others use power across the week. SA Power Networks needs to have sufficient network capacity for the coincident peak demands to ensure a safe and reliable network capable of supporting all consumers' needs.

Tariff development in the past has included the use of demand tariffs for larger commercial and industrial customers, and inclining block tariffs for smaller customers including ToU charges to differentiate for energy consumption between peak and off-peak times.

This has satisfied our needs within the principles of cost reflectivity and simplicity, but the changes that we see developing now have a stronger influence on our network than they have had in the past, and we need to consider these within the principles of:

- empowering the consumer
- fairness and equity
- simplicity (to inform decision making)
- compliance with the Rules.

C.2.2 New influences

The new influences we are facing today include a number of technologies that have forced utilities to become more agile in the way they respond to and plan for changes in the use of the network. This is particularly so for South Australia where the take up of solar for example, continues to grow and whilst the technology is well established, it is the total volume of solar and the size of the installations which are driving significant changes in the network.

Therefore, the new influences in the South Australian network that we need to consider are as follows:

- ***Solar*** – More than 30% of households have installed solar on their rooftops. In addition to this, hospitals, shopping centres and other commercial installations are commissioning significant solar systems that are driving network considerations. A recent study by Energy Networks Australian and the CSIRO predicts that most of our substations will need to be capable of handling reverse flows during the next reset period. In its 2018 South Australian electricity report, AEMO forecasts that SA will experience a negative demand by 2023-24[22]. Importantly, our customers want to be able to export to the network any excess energy they generate to maximise their investment, which results in a significant coincident demand during the highly productive solar peaks. Our network needs to respond to that, and our tariff development process should consider this, to see if it is appropriate or necessary to provide pricing signals to respond to this development. As a minimum, the significant use of solar has moved the peak demand for the day as discussed elsewhere in this Appendix.

- *Response: We need to consider where summer demand is growing. We also need to deal with minimum demand and reverse flows particularly on the low voltage network on mild sunny days when solar energy is abundant.*

- ***Demand*** – Whilst peak demand has been a significant driver of network costs in the past as we have built the network to supply the summer peak, this has changed recently with the combination of solar and energy efficient appliances (including air-conditioning and LED lighting). So, whilst customers are growing and there are local areas of peak demand growth, peak demand growth in some areas is being offset by the increase in solar, and the upgrading of appliances to more energy efficient models.
  - *Response: We need to consider what impact solar is having on demand, and the shift in the time of the peak usage during the day (the peak window).*

- ***The influence of the Adelaide CBD*** – There is a significant commercial load in the CBD, and a growing residential demand in high rise structures. Compounding this is the limited use of solar due to the volume of roof space available and the aspect for solar capture. The demands for this sector will differ from the other areas of the state.
  - *Response: We need to consider the impact of any specific locational demands on the network.*

C.3 The determination of the peak demand window

Development of tariffs has traditionally considered the drivers of network costs, which are ostensibly driven by the coincident peak demand. It is the size of this peak demand, and when this occurs that needs to be considered to determine which customers are driving network costs. In the consideration of "when" we will have regard to seasonal issues (summer, winter and shoulder months), work days and weekend, and the time of day (which considers underlying demand and the impact of solar feeding into the network.)

In this analysis we are using available historical data and forecasting data from known trends to determine the answers to the following questions.

Number	Question	Where addressed in this appendix
1	What is the peak demand window today? What will it be in 2025 when the next increment of solar has been installed?	C.3
2	Is the window common to all of South Australia? Where does it vary significantly? Does it warrant a separate treatment for the large customers (>160 MWh) in the unique areas?	C.4
3	What time of year is the Peak Window open? (Is it November through March).	C.5
4	Does the window/level of demand vary in these 'regions' according to work-day and non-work day? Does it make more economic sense to treat such days as 'peak' or as 'off-peak'?	C.6

[22] *AEMO South Australian electricity report – November 2018, page 4*

5	How should we incorporate these 'windows' into tariffs? Options include: a) Agreed Demand tariffs. b) Actual Demand tariffs. c) Residential Prosumer Demand tariffs. d) ToU Energy tariffs – Small business. e) ToU Energy tariffs – Residential.	

C.3.1 *Peak demand window observations*

Much of the network costs are relatively fixed in nature. That is, they do not increase or decrease with the rise and fall of demand during the year. However significant additional costs are incurred to meet the peak demand when customers are consuming energy to support their demands which are driven by air-conditioning, lighting, and industrial and commercial loads. Traditionally this has occurred during the coincident peak times when residential load is growing in the afternoon, and the commercial and industrial loads are still present on the network. A decade ago, this would have occurred in the afternoon on hot days in summer.

However, with the take up of solar, our network peak has experienced two changes:

- *The peak is not growing as it used to.* The growth in demand driven by increased consumption in appliances and growth in customer connections is being offset to some degree by energy efficient appliances (air-conditioning and lighting for example), and the output from the solar which is growing in the number of connections and size of installations.

- *The peak has moved*. Our peak demand window used to be in the afternoon, but with the generation output from solar, there is significant output capacity in the early afternoon, tapering off as the sun falls in the late afternoon. So, some of our afternoon peak is covered by the solar output. This shifts the overall network peak to later in the day[23].

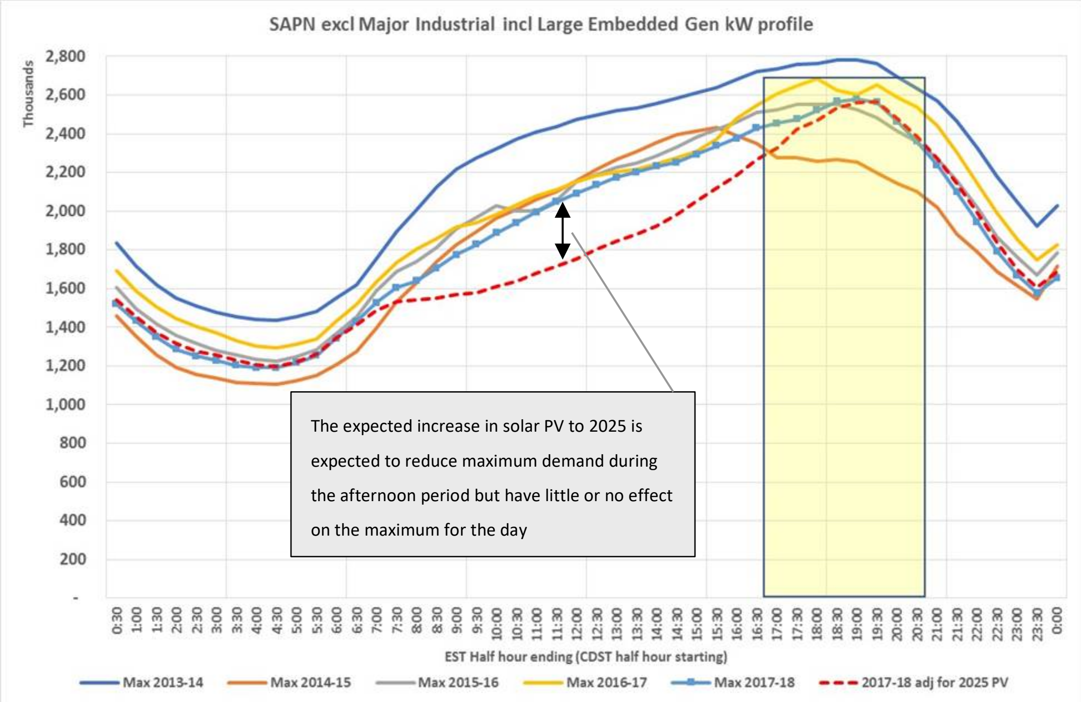
The charts below plot the peak demand and its change over time and identifies at what part of the day this peak window occurs.

Figure 17.26 shows how the maximum demands have changed over time. It is important to note that the forecast effects of the expected solar installations have a dramatic effect on the mid-afternoon maximum demands but have no impact on the evening peak.

In comparing the different years, one should note that 2013-2014 was a particularly hot summer, 2015-2016, and 2017-2018 also suffered heat wave conditions, consistent with the observed demands.

[23] *This is also confirmed by AEMO which notes that the peak demand now occurs at 7:30pm Adelaide time (AEMO's South Australian electricity report November 2018)*

Figure 17.26: Network maximum demands by year



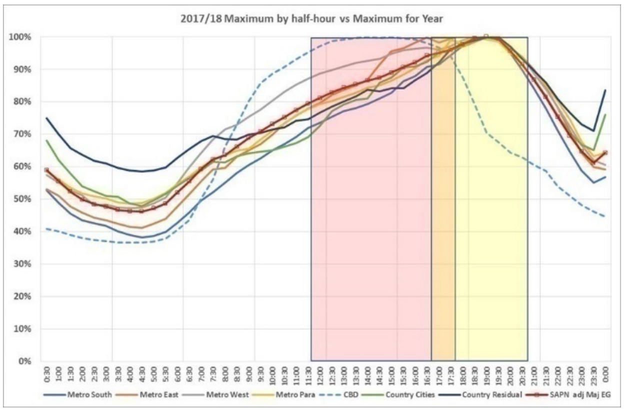
Source: SA Power Networks analysis

In Figure 17.27, we have presented the Maximum Demand for the peak day with the maximum demands for the year to show when the peak occurs. This normalises all the sub-regions to make the sub-region comparison easier.

If we observe the 2017-2018 maximum demands by sub-region, it is relatively clear that most regions have a coincident peak that occurs around 7:00pm to 7:30pm in the evening. The exception is the CBD sub-region, with a commercial load that holds a peak from about 1:30pm until 4:00pm.

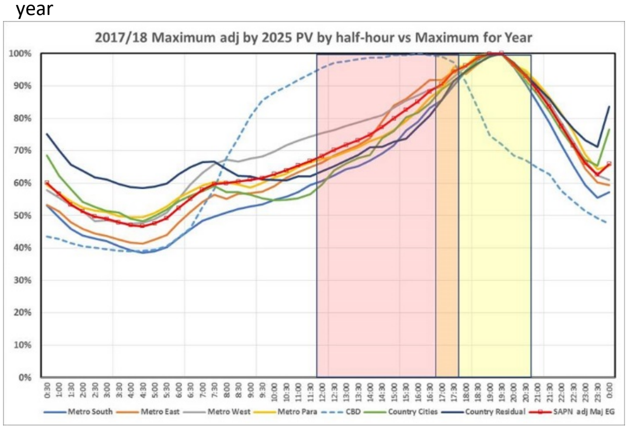
In Figure 17.28 we have applied the forecast solar take up to 2025 against the 2017-2018 data to demonstrate the effect of solar in these regions. Again, whilst the effect of solar reduces demand in the afternoon, it is not expected to influence the evening peak. We therefore expect that the evening peak is likely to remain around 7:00pm to 7:30pm through to 2025.

Figure 17.27: 2017-2018 Network maximum demands by half hour as a percentage of maximum demand for the year



Source: SA Power Networks analysis

Figure 17.28: 2017-2018 Network maximum demands by half hour adjusted for 2025 Solar - as a percentage of maximum demand for the year



Source: SA Power Networks analysis

C.3.1.1 *Peak demand window conclusion*

The previous figures demonstrate we have identified a peak demand window that covers the period from about 5:00pm through to 9:00pm – a period of four hours for all sub-regions excluding the CBD. During this time demands for all sub-regions (excluding the CBD) are around 95% at 5:00pm, rising to 100% around 7:00pm and falling away to 85% to 95% (depending on the sub-region) by 9:00pm. It makes sense to consider a peak demand window for all sub-regions around the period that covers approximately 90% of the peak demands.

With regard to the CBD it would appear that the peak demand window is earlier (1:30pm to 4:00pm) and therefore covered by the six-hour period of 11:00pm to 5:00pm.

C.4 Locational zones

C.4.1.1 *Consideration of sub-regions*

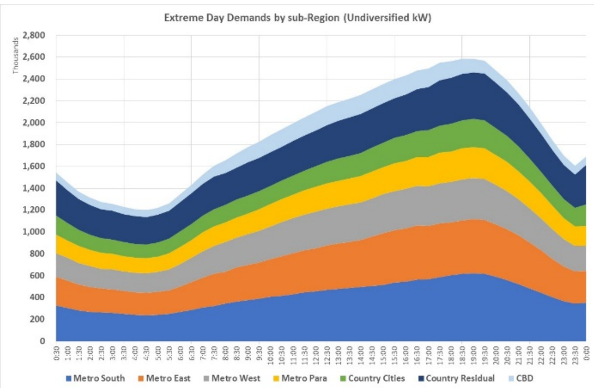
To establish different usage patterns across the state, SA Power Networks has established a number of sub-regions in which to conduct the analysis. These sub-regions were chosen to group customer types into a limited number of areas specified as:

- CBD (split of the East transmission zone)
- East metropolitan
- South metropolitan
- West metropolitan
- North (Para) metropolitan
- Country cities (Mt Barker, Pt Lincoln, Whyalla, Pt Augusta, Pt Pirie and Mt Gambier including surrounding areas supplied from that Transmission Connection)
- All other country areas (the Residual) including Yorke Peninsula, Barossa, Riverland, Murraylands, Upper-South East and Eyre Peninsula (excluding southern Eyre/Pt Lincoln which is included in Country cities)

These sub-regions were tested to determine if there was any discernible difference in usage at various times of the day, week and year.

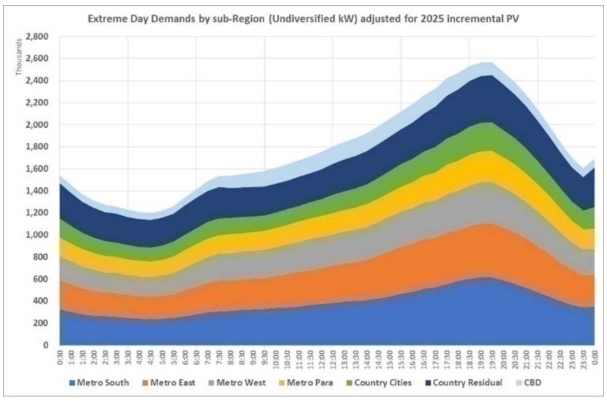
The following figure (Figure 17.29) sets out the size of the relevant sub-regions during an extreme demand day in the period 2013-2014 through to 2017-2018. Figure 17.30 sets out our forecast for the extreme day demands by sub-region after allowing for the growth in solar installed by our customers to 2025.

Figure 17.29: Extreme day demands by sub-region (historical)



Source: SA Power Networks analysis

Figure 17.30: Extreme day demands by sub-region forecast for 2025



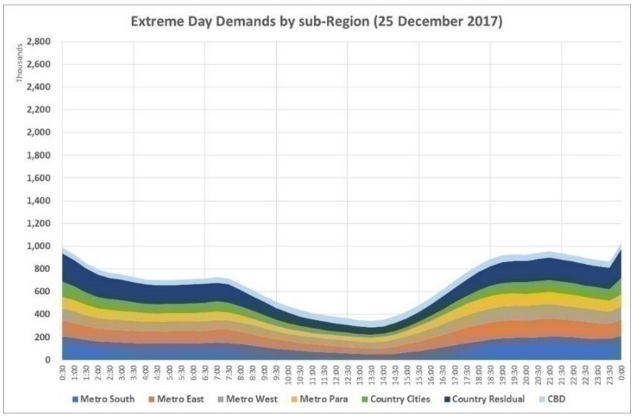
Source: SA Power Networks analysis

The higher solar output in the period leading up to the evening peak has removed some of the total net demand during the afternoon when solar is performing well but has had no impact on the daily peak demand which occurs around 7:00pm in the evening. The additional solar has had an impact on the slope of each sub-region except for the CBD where there is less opportunity for the take up of solar by our customers.

It is worth noting whilst figures demonstrate the net peak demand on the network, they do not show the local demands across the network and the energy flows from solar generation from the ‘producer customers’ to the ‘consumer customers’ across the low voltage network. There is now sufficient solar installed within the South Australian network to supply the South Australian demand at certain times of the day on some days of the year.

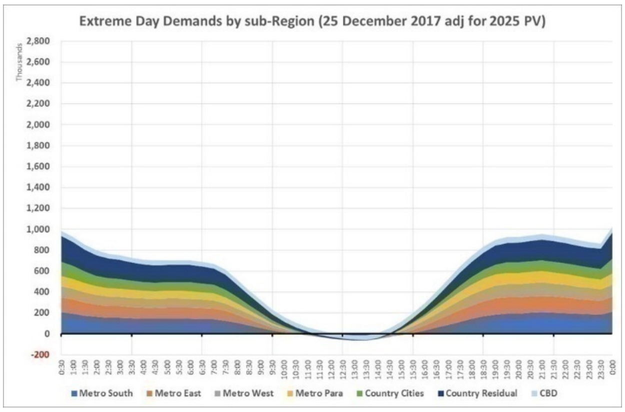
Figure 17.31 shows the combined effect of solar and a low demand day based on actual data for 25 December 2017. The total use on the network is understated by the effect of the solar generation from some customers. This effect is amplified by the anticipated increase in solar expected to be connected in the network by 2025 as demonstrated in our forecast depicted in Figure 17.32. In this forecast, the modest load during the middle of the day is completely covered by the available solar generation expected in the network for a few hours. Residual demand grows after about 2:30pm and grows steeply as the effect of solar diminishes between 6:00pm and 7:00pm.

Figure 17.31: Extreme day demands by sub-region 25 December 2017



Source: SA Power Networks analysis

Figure 17.32: Extreme day demands by sub-region 25 December 2017 adjusted for solar forecast for 2025

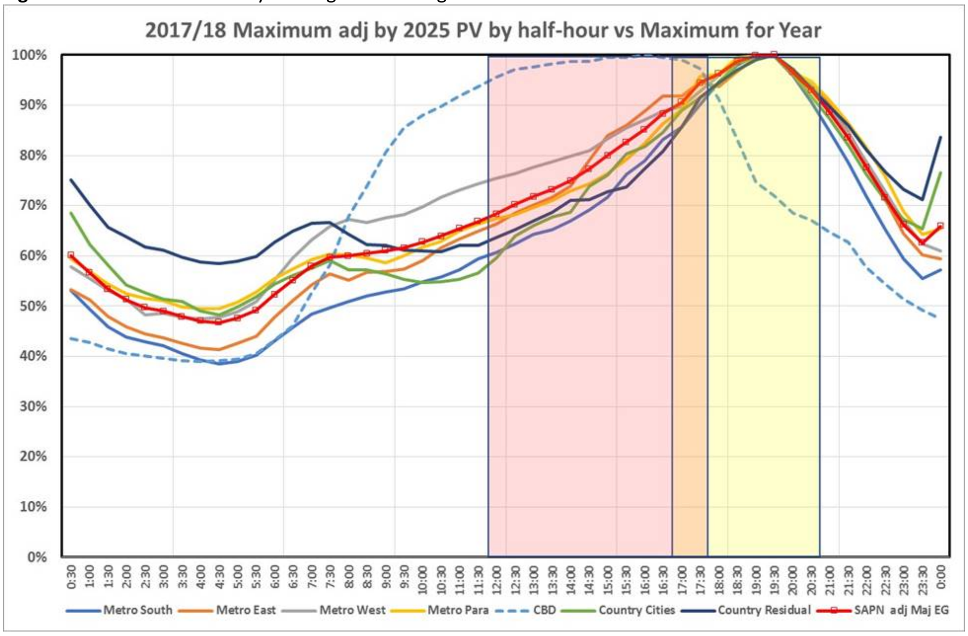


Source: SA Power Networks analysis

C.4.1.2 *Peak demands by sub-region*

The chart below demonstrates the coincident peak demand by sub-region expressed as a percentage of the maximum demand on the peak day, and a percentage of the maximum demands. It normalises for the size of the demand in each region to show when the peak occurs in the day. It can be seen from Figure 17.33 that all the sub-regions have a peak that is experienced around 7:00pm, except for the CBD.

Figure 17.33: Peak demand by sub-region including forecast Solar to 2025



Source: SA Power Networks analysis

C.4.1.3 *Conclusion on sub-regions*

The data demonstrates that most of the state excluding the CBD has a similar peak demand profile. The CBD with its higher commercial loads and lower solar penetration has an earlier and flatter peak and could be treated differently.

C.5 Seasonal demand

C.5.1.1 *The influence of the seasons on the timing of the peak window*

South Australia's peak electricity demand is driven by the extreme temperatures of our hot dry summers.

This has traditionally been due to the coincident air conditioning demand which has grown steadily over the past few decades. As new, more efficient air-conditioning equipment replaces older appliances, the growth is demand is fairly modest, but the summer peak still produces the highest demand for the year.

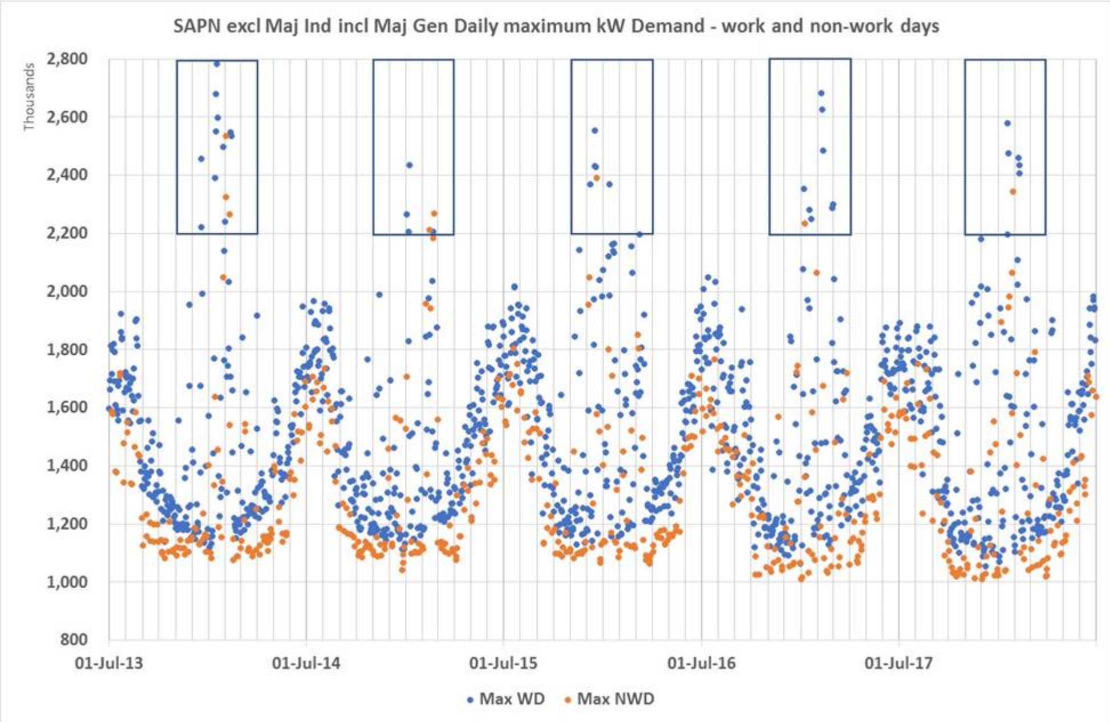
The summer peaks have traditionally occurred in the period from November to March each year. Whilst some peaks have occurred outside of this window, they are infrequent and more localised rather than coincident across the state.

In considering this window, it is necessary to balance the length of the window (in this case five months) against the period that captures the majority of the peaks. Further, the behaviours that a tariff methodology might employ should cover the behaviours of the customers over the period in which the peaks are likely to occur, and smooth out any potential for significant peak pricing which is difficult for customers to manage, and potentially too complex to understand.

The analysis conducted is demonstrated in the identification of peak demand on working days and non-working days for five years in three locations comprising:

- The entire SA Power Networks service area in South Australia
- Country regions excluding country cities
- Adelaide metropolitan north (Para region)

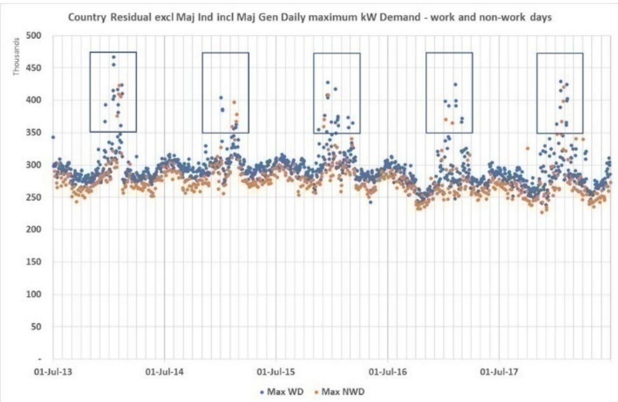
Figure 17.34: Peak demand for South Australia excluding Major Industry Including Major Generation – Seasonal Blocks



Source: SA Power Networks analysis

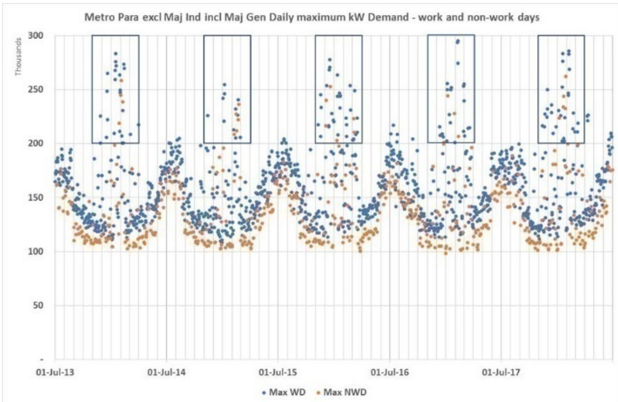
The chart above demonstrates that across the state, the peaks for work days and non-work days are covered in the peak summer period November to March across the five years to 30 June 2018.

Figure 17.35: Peak demand for country – excluding country cities – Seasonal Blocks



Source: SA Power Networks analysis

Figure 17.36: Peak demand for Metro Para – Seasonal Blocks



Source: SA Power Networks analysis

The analysis shows that for country regions peaks are occurring again within the window from November to March, with a particular spread of peaks in the summer of 2015-2016 from early November to late March. The Para data above demonstrates that the summer of 2015-2016 shows a similar spread of peaks within that period from November to March but does not capture two April peaks (above 200 MW for that region) in 2018.

C.5.1.2 *Seasonal demand conclusion*

In conclusion, where it is necessary to determine a period of time that can be used for peak demand pricing for particular customer groups, the period from November to March covers the majority of peak demand times covering the SA Power Networks service area.

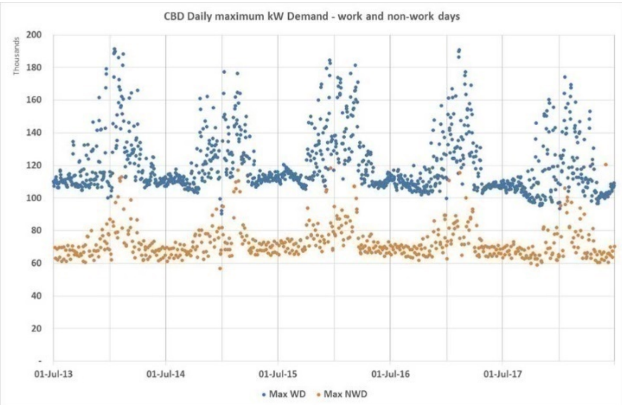
C.6 Work day versus non-work day

Determining the different demands on work days compared to non-work days is important to the consideration of the drivers of demands during these periods and the potential for simplifying any tariffs that might respond to the differences observed.

C.6.1.1 *Maximum demand data – work day and non-work day*

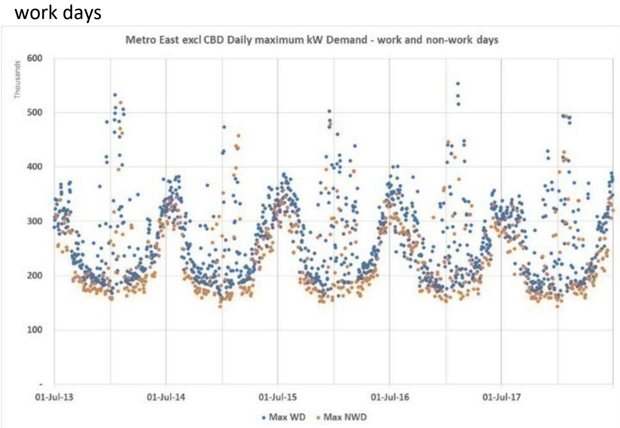
The following series of charts plot the maximum demands by day, applying a different colour for a work day as compared to a non-work day for the five-year period 2013-2014 to 2017-2018. If there was a significant separation of the work day and non-work day data, there could be a case for a differentiation in a tariff for work day and non-work day consumption/demand.

Figure 17.37: CBD - Daily maximum demand work and non-work days



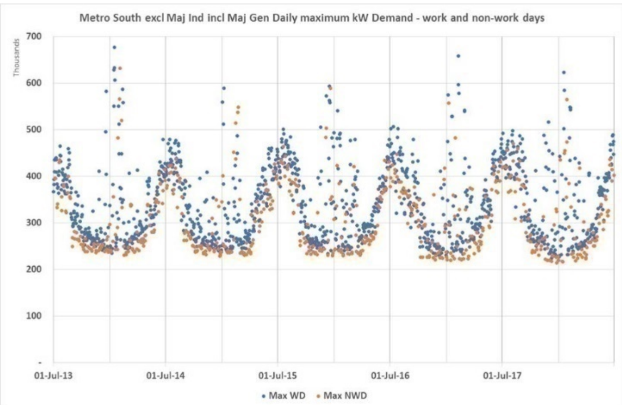
Source: SA Power Networks analysis

Figure 17.38: Metro East - Daily maximum demand work and non-work days



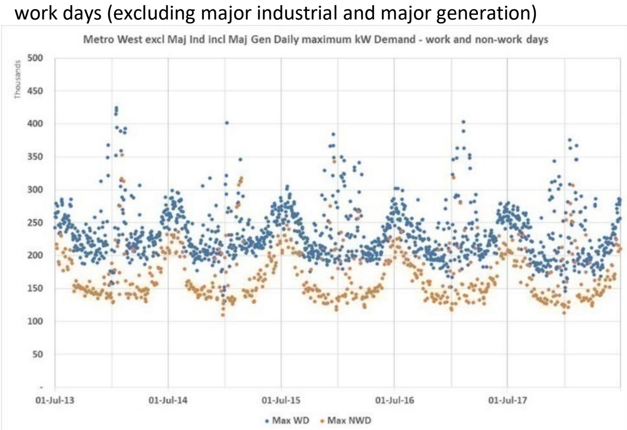
Source: SA Power Networks analysis

Figure 17.39: Metro South - Daily maximum demand work and non-work days (excluding major industrial and major generation)



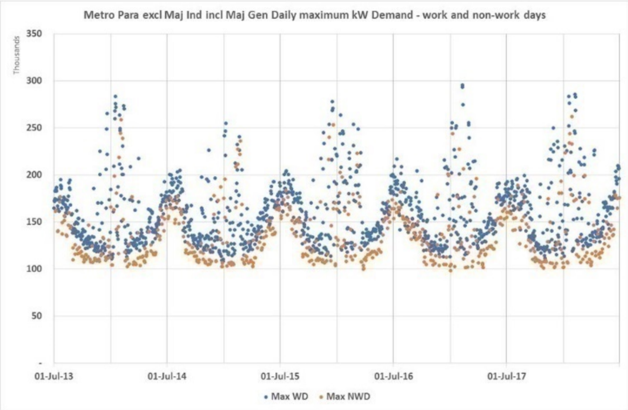
Source: SA Power Networks analysis

Figure 17.40: Metro West - Daily maximum demand work and non-work days (excluding major industrial and major generation)



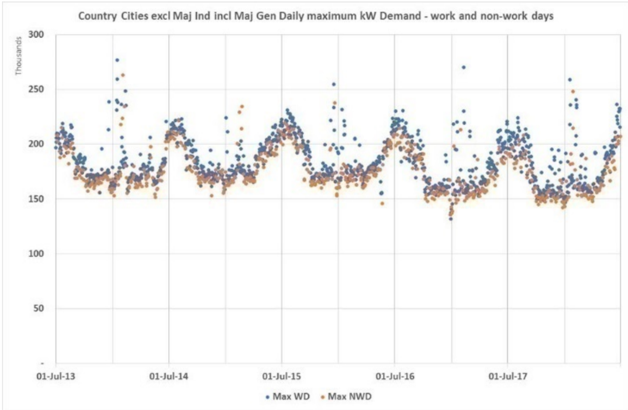
Source: SA Power Networks analysis

Figure 17.41: Metro Para - Daily maximum demand work and non-work days (excluding major industrial and major generation)



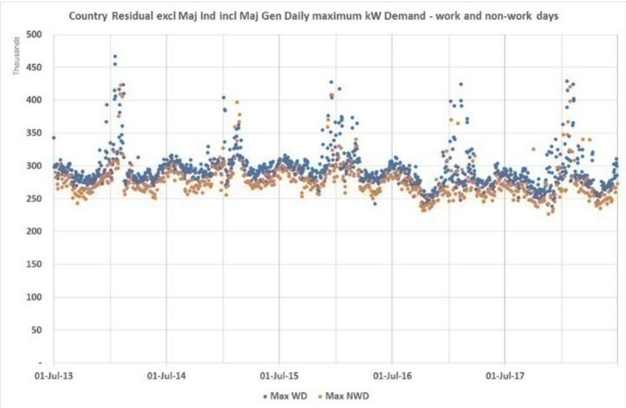
Source: SA Power Networks analysis

Figure 17.42: Country Cities - Daily maximum demand work and non-work days (excluding major industrial and major generation)



Source: SA Power Networks analysis

Figure 17.43: Country Residual - Daily maximum demand work and non-work days (excluding major industrial and major generation)



Source: SA Power Networks analysis

In Metro West (Figure 17.40), the data shows a difference between work days and non-work days, but there is still some significant overlap on some peak days each year. Similarly Metro Para (Figure 17.41) data shows that whilst there is some difference observable between the work day and non-work day, there is again, sufficient overlap each year to discount this as a consistent trend in the data. In all other cases except for the CBD, there is significant overlap between the maximum demands during a work day and a non-work day suggesting that the circumstances of a work day, or a non-work day are not particular drivers of maximum demand.

The CBD however does have sufficient delineation to suggest that the commercial load which is present during a work day is not present to drive demand on the non-work days. Even though retail and residential loads are present on non-work days within this sub-region, the data suggests that they do not offset the influence provided by the commercial loads of the office buildings supporting the services sectors in this sub-region.

C.6.1.2 *Conclusion*

Therefore, it is reasonable to conclude that there is no need for tariff differentiation between work day and non-work day in the South Australian customer base except for the CBD sub-region.

C.7 Conclusions – Peak demand window

Number	Question	Where addressed in this appendix	Conclusion
1	What is the peak demand window today? What will it be in 2025 when the next increment of solar has been installed?	C.3	The analysis suggests a period of four hours for all sub-regions excluding the CBD commencing at 5:00pm and concluding by 9:00pm. With regard to the CBD it would appear that the window is earlier and covered by the six-hour period 11:00 am to 5:00pm. The increase in solar to 2025 does not appear to alter this peak window.
2	Is the window common to all of South Australia? Where does it vary significantly?	C.4	The data demonstrates that most of the state excluding the CBD has a similar peak demand profile. The CBD with its higher commercial loads and lower solar penetration has an earlier and flatter peak and could be treated differently.
3	What time of year is the Peak Window open? Is it November through March?	C.5	The data demonstrates that the period of November to March covers the majority of peak occurrences in a year. Both November and March experience severe weather.
4	Does the window/level of demand vary in these 'regions' according to work-day and non-work day? Does it make more economic sense to treat such days as 'peak' or as 'off-peak'?	C.6	The observations suggest it is reasonable to conclude that there is no need for tariff differentiation between work day and non-work day in the South Australian customer base except for the CBD sub-region. The rest of SA peak in early evening and this is not affected by work/non-work day differences.
5	How should we incorporate these 'windows' into tariffs? • Agreed Demand Tariffs • Actual Demand Tariffs • Residential Prosumer demand Tariffs • ToU Energy tariffs – Small business • ToU Energy Tariffs - Residential		We are interested in the after-diversity impact of customers on peak demand. For our largest customers (major business), the demand over a half hour can cause a difference. For most customers though, the average demand over the window is more important, and a simpler signal to respond to for customers. For demand measures we use the average over the 5:00pm to 9:00pm window (11:00am to 5:00pm CBD). For ToU small business we use the four-hour window as a peak price period.

Appendix D. Customer Impacts

D.1 Introduction

In this appendix we have considered the impacts of various approaches to determine how tariffs might be developed to respond to the emerging needs, whilst retaining simplicity, cost-reflectiveness, fairness and equity and tariffs that empower the customer to manage their energy needs.

The analyses and discussion are provided by tariff class below.

D.2 Customer groups

Different customers have different influences on the use of the network and use the network at different times. Further, some customers are able to respond to changes whereas other customers cannot.

Our peak load now occurs in the early evening when the combined effects of high demand, and the benefits of solar generation are tapering off as the sun moves lower in the sky. Businesses that operate in what we call normal business hours between 8:00am and 5:00pm have little opportunity to move load into an afterhours time slot simply because they are not open for business after the usual close of business day at 5:00pm.

D.3 Residential Tariff Class

The changes proposed in this tariff class are limited in part by the availability of metering, but as acknowledged in this TSS, metering technology is changing across this customer group and the changes proposed exploit the current and future metering options, without burdening those customers who remain on old metering technology in the interim.

A new option is proposed for those customers who want to proactively manage their energy needs.

- **Residential single-rate (Type 6)** - There is limited opportunity for the development of tariffs for residential customers with a Type 6 accumulation meter. However, the proposed new tariff is simpler for this class with no seasonal pricing and no inclining block structure for consumption within a quarter. It is forecast that the number of customers on this tariff will decline over the 2020-25 RCP as more customers take up ToU meters with 'Power of Choice', new building construction and other electrical upgrades at customer premises which may initiate the upgrading of metering to Type 4 meters.

- **ToU (Type 4)** – For customers with ToU metering, two five-hour off-peak windows are introduced each day (not discriminating between work day and non-work day). This offers an incentive for customers to move load into these off-peak times where they can. The off-peak windows are driven by the:

    - 'solar trough' (the period in which the solar residential production is at its highest); and
    - night time periods after the start of the 'Off-peak controlled load' period (when the controlled load hot-water consumption declines).

  Another advantage of this proposed tariff is that it also provides signals for customers to exploit off-peak times for the charging of electric vehicles. Whilst not proposed to have a significant effect in the 2020-25 RCP, the influence of electric vehicles is forecast to grow, and this tariff will assist in reducing the impact of an otherwise anticipated electric vehicle driven peak in the future.

It is not proposed to have a seasonal tariff in this class and each day of the year is treated in the same way. The reason for this is that:

- The tariff proposed is set to deal with the low voltage and only some of the high voltage issues.
- The ToU residential customers are not likely to cause significant upstream augmentation.
- There are further energy efficiency gains to be realised when the older (pre 2005) air-conditioning is replaced with more efficient current technology.
- The growth in the 'Prosumer' is likely to have some impact in the future when technology enablers support Prosumers managing their loads.

By introducing two five-hour off-peak windows it is forecast that the off-peak price can be offered at some discount without having a significant impact on the 'shoulder' (alternative to off-peak) price. This should deliver a tariff that is not very complex but delivers on the need to respond to the changes and reform tariff structures.

- **Prosumer** – For customers with ToU metering and battery installations that can be used to manage demand.

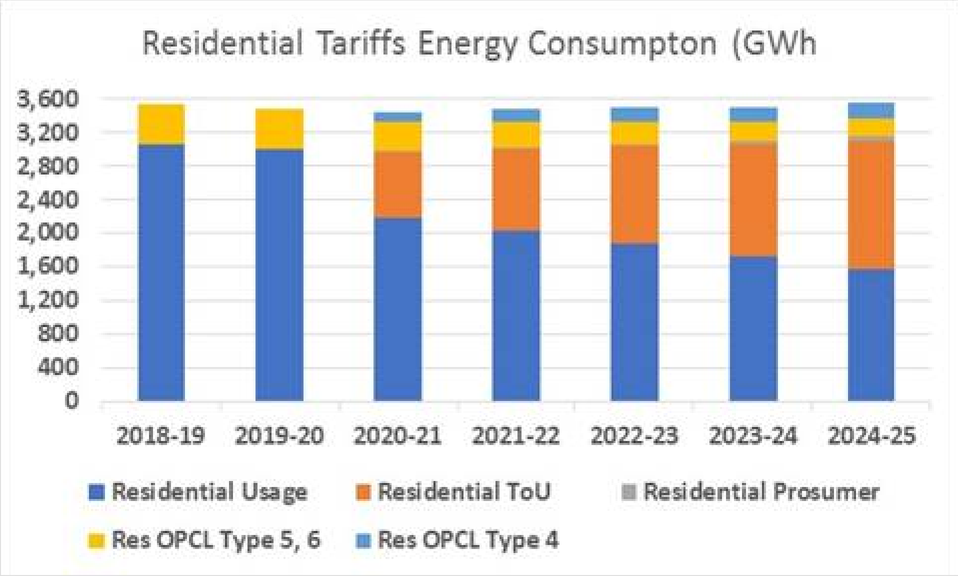
  This is a new tariff for the 2020-25 RCP which introduces a peak demand charge for a four-hour window between 5:00pm and 9:00 pm each day and measured as the highest average daily demand for the month, during the months of November to March in each billing year (financial year ending June). The peak demand for a day is calculated from the average demand during that four-hour window. This is simple, provides the right signals, empowers the customer and is cost-reflective. Using the average demand for the four hours allows for some diversity across the customers' usage during that time and simplifies the response by the customer, rather than having the customer try and manage each half hour demand for example.

  The period of November to March is chosen for the peak demand assessment as this coincides with the historical peak demand on the distribution system. (Refer to Appendix C for discussion on the timing of the peak demand window.) It is possible that having a peak demand charge that is applied for a five-month period may introduce bill variability for the customer and cash flow issues for SA Power Networks. To alleviate any cyclical issues associated with a seasonal demand charge, a subscription or standard charge could be applied monthly for the year based on an agreed demand, and the monthly bills during November to March could represent adjustments to the agreed demand, reducing cash flow variations whilst keeping the tariff structure simple and transparent.

  A Critical Peak Pricing component was considered for this tariff however during the consultation process the feedback suggested that this would add to the complexity and it was resolved that this would be excluded on the principle of simplicity. SA Power Networks believes that the design of the ToU and Prosumer tariffs offer sufficient incentives to move demand where possible and avoid the complexities of Critical Peak Pricing.

It is expected that customers will move between tariffs over time as metering technology changes, and as customers become more engaged with energy management. A forecast of the energy consumption by residential tariff class is presented below. It demonstrates the decline in energy volumes from the old Accumulation Type 6 meters as they are progressively withdrawn from service, replaced by energy consumed and metered through ToU and Prosumer tariffs.

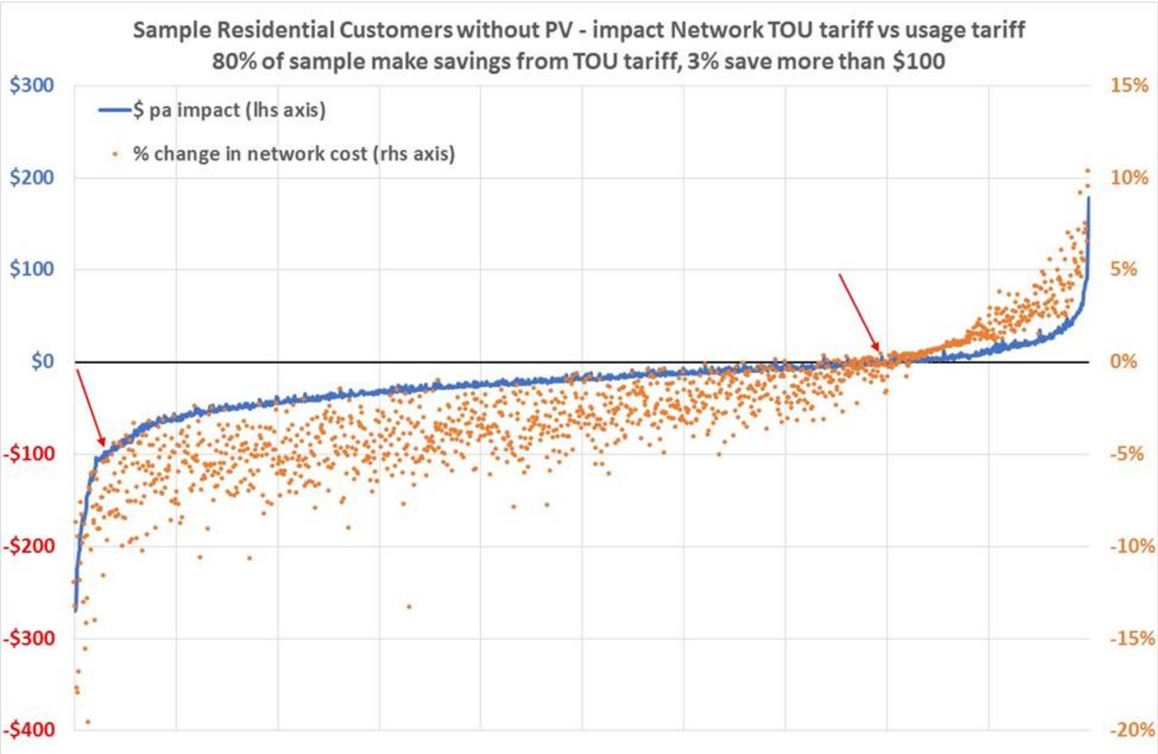
Figure 17.44: Residential tariff forecast energy consumption by class



Source: SA Power Networks analysis

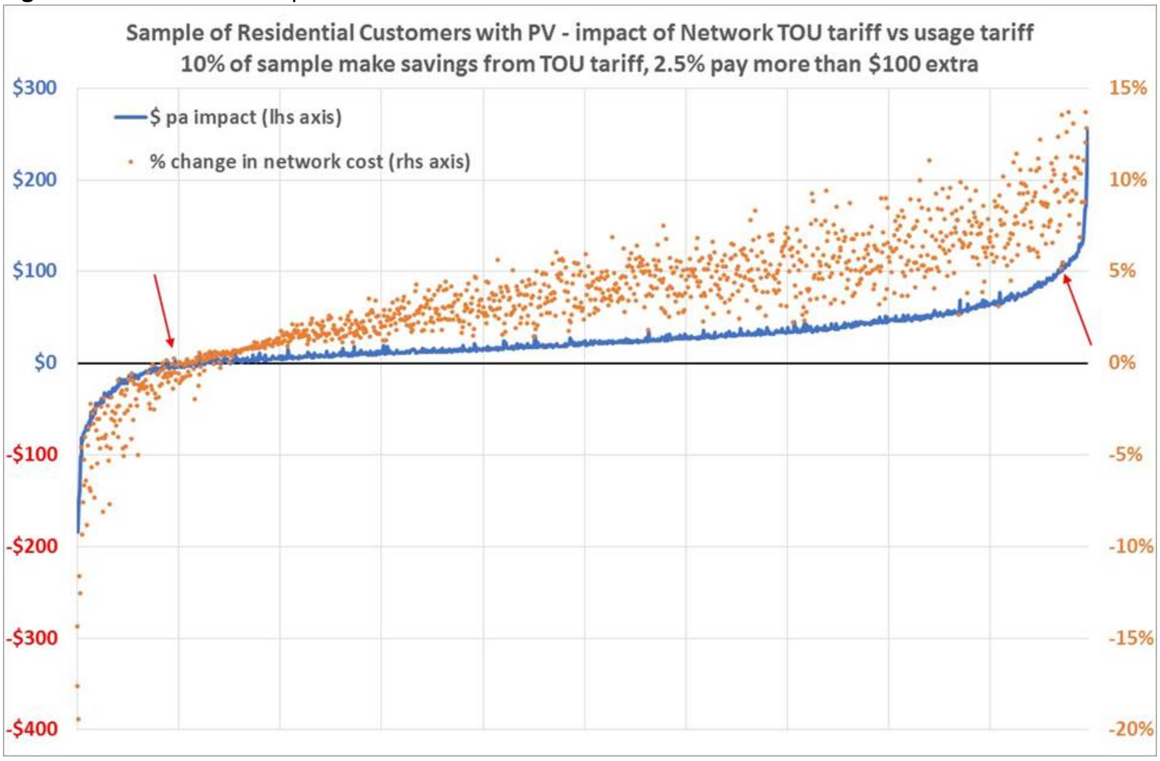
Customer impacts for residential customers is demonstrated below. The propeller charts maps two parameters for each customer in the sub-class. The blue dot represents the $ saving created by the change, from best to worst outcome. For each blue dot (one per customer) there is a corresponding orange dot that represents the percentage change that the proposed tariff will cause to the customers total network charge.

Figure 17.45: Customer impacts - residential customers without solar



Source: SA Power Networks analysis

Figure 17.46: Customer impacts - residential customers with solar



Source: SA Power Networks analysis

The two charts above demonstrate that the impact of the change to ToU tariffs is manageable with:

- 80% of customers without solar making a saving; and
- Only 2.5% of customers with solar paying more than $100 extra pa;

therefore no transitional arrangements are proposed for the Residential class.

D.4 Small business Tariff Class

Existing tariffs

Small business customers consume energy measured through either a Type 6 accumulation meter, or a Type 4 interval meter. The existing tariffs applied to the Small business tariff class include:

- Small business – single-rate
- Small business – two-rate
- Small business – ToU
- Small business – actual demand
- Small business – transition actual demand (a mix of Two-rate and actual demand)

This group is characterised by the following attributes:

- Some customers that might have been described as 'large' are still using the agreed demand tariff.
- About 65% of energy consumed by this customer group is supplied through Type 6 meters for customers on either a single-rate or two-rate tariff.
- About 15% of energy consumed by this customer group is supplied through interval meters but for customers who still elect to take the supply on a single-rate or two-rate tariff.
- About 20% of energy consumed by this customer group is supplied through interval meters on demand tariffs.
- The significant majority of small business customers have low annual consumption, have Type 6 meters and either use a single-rate or two-rate tariff.

Customer feedback

During our customer and retailer engagement process on tariff development in particular, the feedback from business customers recognised that the tariff should be simple for small business customers. We have taken that on board and simplified the structures where appropriate and not introduced more complex structures to respond to the changes on the network.

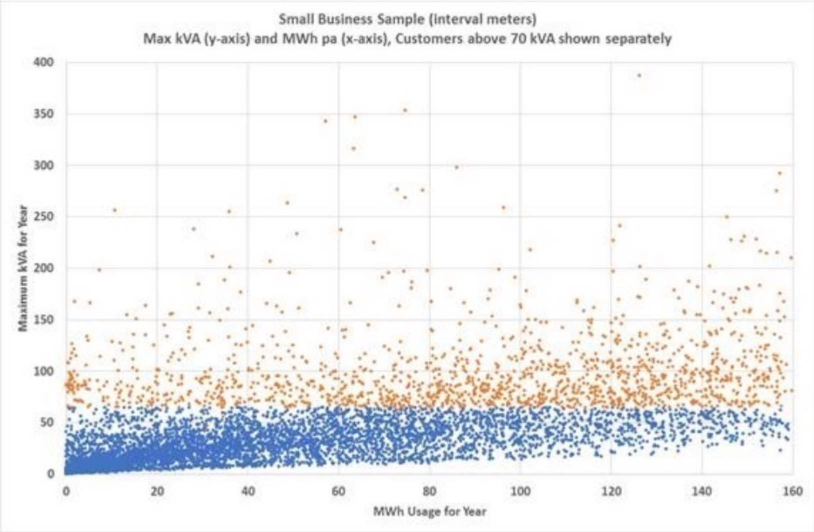
Further, it was noted that within the small business sector, there is a reasonable amount of diversity of demand across this customer class. For example, some small businesses do not operate during normal business 7:00am to 9:00pm peak times, and some do not operate each work day in a week, or each month within a year. For example, the local bakery and coffee shop working seven days per week may close for business before the pizza bar opens for business in the evening. This diversification has been considered in developing the tariffs for this customer class.

Our analysis of this class of customers, and their potential tariff impacts is presented in the sections below. We have tested the consumption patterns against the proposed tariffs to determine impacts and equity of charging (the distribution network costs) of the customers to assess if simpler structures have adequate outcomes compared to more complex structures. If the cost reflectivity and equity of charging is achieved in a simpler structure, then the simpler structure should prevail. This is what the customers have asked for. Simpler structures also empower the customer through better decision making to manage their energy needs.

Small business electricity characteristics

The energy consumption and demand patterns of the Small business tariff class are quite diverse as the following chart (Figure 17.47) demonstrates. For a given maximum demand, there is a range of energy consumptions that need to be considered in developing tariffs for this class.

Figure 17.47: Small business comparison of demand and energy consumption patterns by customer



Source: SA Power Networks Analysis

Note: Customers with demands above 70 kVA shown in orange, below 70kVA shown in blue

The diverse nature of the customers and the existing tariffs can be further demonstrated in the following charts where it shows the different charges for customers with a given energy consumption. The different tariffs are identified by different colours and includes the following tariffs (the abbreviations identify the customers with those tariffs listed below):

- Small business two-rate (**B2R**)
- Small business single-rate (**BSR**)
- Small business actual demand (**SBD**)
- Small business actual demand transition (**SBDT**)
- Small business agreed demand (**SLV**)

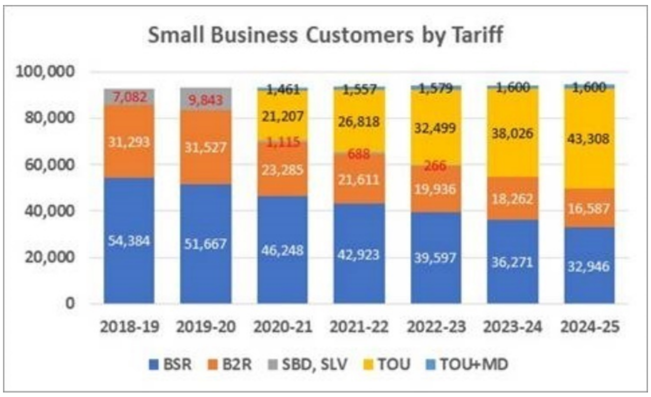
The left-hand chart below shows those customers with less than 70kVA whilst the right-hand chart shows those customers with higher demands, greater than 70kVA.

We have chosen the value of 70kVA to differentiate customer groups because:

- it keeps tariffs simple for the for the majority of small customers;
- a customer above 70kVA tends to dominate the demand on local network assets; and
- different metering installations (with CT transformers) are normally required for customers with demand above 70kVA.

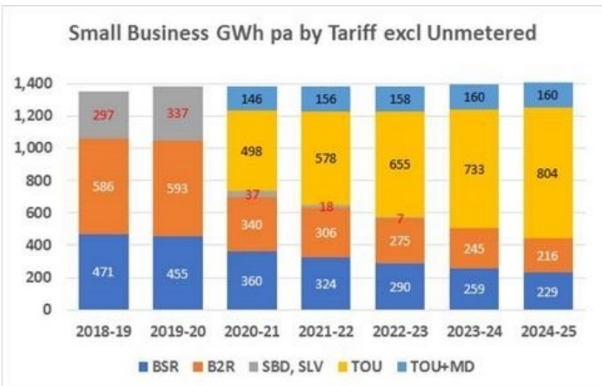
So 70kVA represents a natural boundary for this differentiation.

Figure 17.48: Small business – Customers by tariff



Source: SA Power Networks analysis

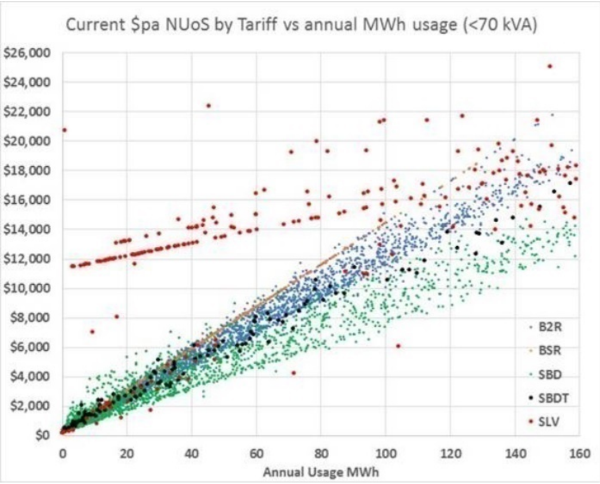
Figure 17.49: Small business – Energy volumes by tariff



Source: SA Power Networks analysis

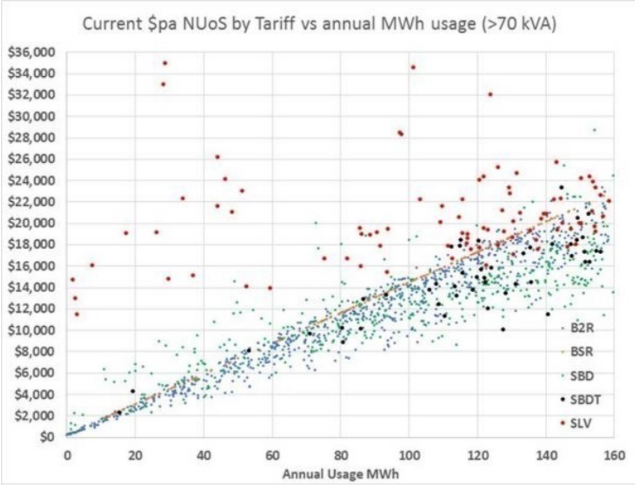
The forecast changes within the small business class can be further demonstrated in two charts above. Figure 17.48 shows the transition to new tariffs allowed through the transition to new Type 4 meters and Figure 17.49 shows the forecast energy volumes by tariff over time.

Figure 17.50: Small business - Comparison of energy consumption and network charges levied (less than 70kVA)



Source: SA Power Networks analysis

Figure 17.51: Small business - Comparison of energy consumption and network charges levied (greater than 70kVA)



Source: SA Power Networks analysis

Analysis of the existing tariff structure for small business tariff customers (as supported by the charts above) has determined that:

- A range of average $/MWh price outcomes is occurring with current pricing structures.
- Similar $/MWh outcomes occur for small business customers less than 70kVA demand (Figure 17.50) and small business customers with greater than 70kVA demand (Figure 17.51).
- BSR and B2R are tightly bunched with Business single-rate paying slightly more as the tariff assumes a higher proportion of peak usage than most business two-rate customers use.
- SBD is paying a lower average $/MWh price. This tariff was developed for larger business which uses less of the network. This tariff appears under-priced for small business.
- SBDT tariff outcomes fit between the B2R and the SBD tariff. The transition tariff uses the average of these two tariffs, hence the outcome, and slight under-pricing.
- SLV tariff was used by larger businesses, some of which have contracted in annual usage but have retained the high agreed demand charge. Most of these customers are over-priced today.

This TSS attempts to address those observations in a fairer manner, introducing simplicity and more equity in the cost-reflective tariffs applied to this tariff class.

Tariff strategy

The proposed tariffs for small business have been adjusted only slightly from the current period to simplify the tariffs, make them more transparent, and apply the cost-reflective principles within a structure that allows the customer to respond to the price signals necessary to reduce costs in the longer term.

The changes by class are outlined below:

- **Small business - BSR (Type 6)** – Similar to the Residential Single Rate tariff, there is limited opportunity for the development of tariffs for small business with a Type 6 accumulation meter, and the structure of this tariff is not proposed to change for the 2020-25 RCP.

- **Small business – B2R (Type 6)** – The metering limitations also make structural change to this tariff more difficult and it is proposed not to significantly alter the structure of this tariff for the 2020-25 RCP.

- **Small business – ToU (Type 4 and 5)** – In order to respond to the network peaks and the other issues that are affecting our network, the tariff needs to recognise the shift in time of the network peak. The simplest way to achieve this is to expand the duration of the peak usage period within this tariff.

  Peak usage was historically measured on work days between 7:00am and 9:00pm. The proposed tariff redefines this as 'shoulder', with peak as a narrower period of 5:00pm to 9:00pm on work and non-work days during the five-month period November to March to recognise the coincident congestion on the network in the summer. Our analysis of the time of peaks demonstrates that there is no significant difference between work days and non-work days in all regions but the CBD. (Refer section C.6 in Appendix C).

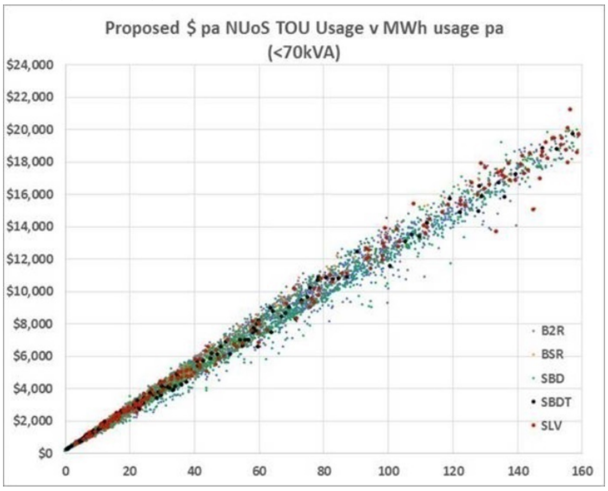
  This tariff also retains an off-peak period during non-work days to coincide with the 'solar trough' which will encourage energy use during times of peak solar output and low demand on the network.

  The anytime demand provides an incentive to manage the size of the connection during the remainder of the year. This signal is proposed to apply to customers using greater than 70kVA. It is not mandated for small business using less than 70kVA.

  We have discontinued the shoulder demand component previously applied to small business demand tariffs and replaced it with the anytime demand charge to simplify the tariff structure. We have introduced a peak, shoulder and off-peak usage tariff to recognise the ToU tariff during the relevant times on the network.

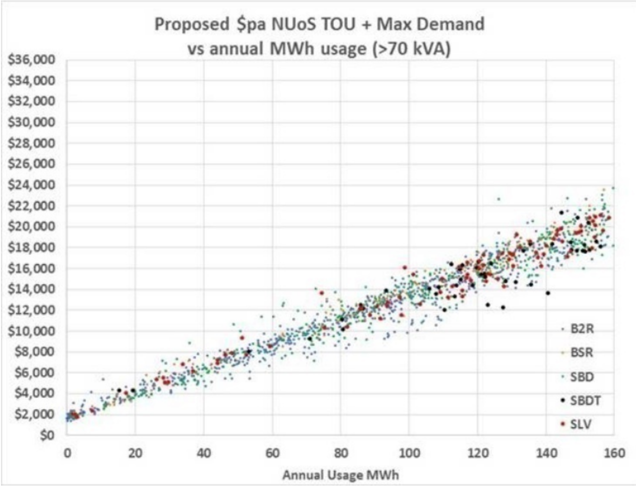
The two charts below (Figure 17.52 and Figure 17.53) demonstrate the outcomes of the proposed tariff structure for the small business tariff class. After analysis of the options, this structure offers cost reflectivity, equity and simplicity.

Figure 17.52: Small business – mapping of proposed ToU tariff to energy consumption (less than 70kVA)



Source: SA Power Networks analysis

Figure 17.53: Small business - mapping of proposed ToU + Maximum Demand tariff to energy consumption (greater than 70kVA)



Source: SA Power Networks analysis

The proposed tariff structure for small business customers with interval meters comprise:

- a supply charge;
- an anytime demand charge (highest 30-minute interval in the last 12 months, customers greater than 70kVA only);
- a peak usage ToU charge (November to March – 5:00pm to 9:00pm);
- a shoulder usage ToU charge (all work days 7:00am to 9:00pm that is not peak usage); and
- an off-peak usage ToU charge (all other times).

The supply and anytime demand charge recover the customer and low voltage system related costs. The usage charges recover the upstream network costs, including high voltage lines and substations, sub-transmission and transmission.

The proposed outcomes across different customers sizes are more equitable than the current arrangements, whilst still providing good signals on the cost-reflectiveness aspects of connection (anytime demand) and upstream congestion (through ToU peak charges). The shoulder and off-peak ToU charges enable an equitable recovery of sunk costs in a similar manner to past practice.

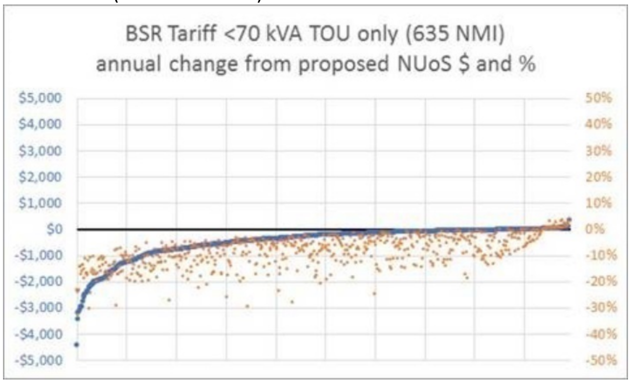
Impact of change in small business tariff class

The impact of the proposed change is demonstrated in a 'propeller chart' for each sub-class of customers within the small business tariff class.

The propeller charts maps two parameters for each customer in the sub-class. The blue dot represents the $ saving created by the change, from best to worst outcome. For each blue dot (one per customer) there is a corresponding orange dot that represents the percentage change that the proposed tariff will cause to the customers total network charge. For example, a smaller business with a $1,000 change will have a higher percentage than a larger business with a $1,000 change.

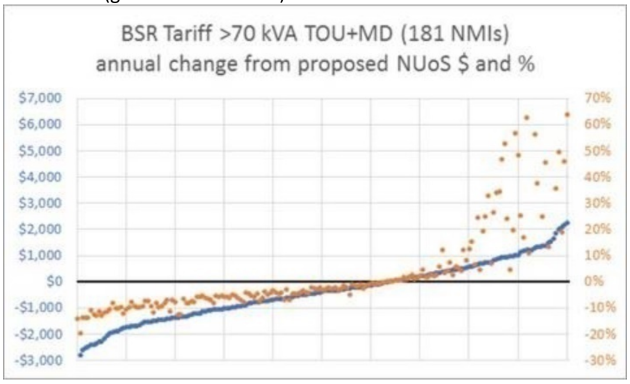
The outcomes are mapped below.

Figure 17.54: Small business – Customer impact in Single Rate tariff customers (less than 70kVA)



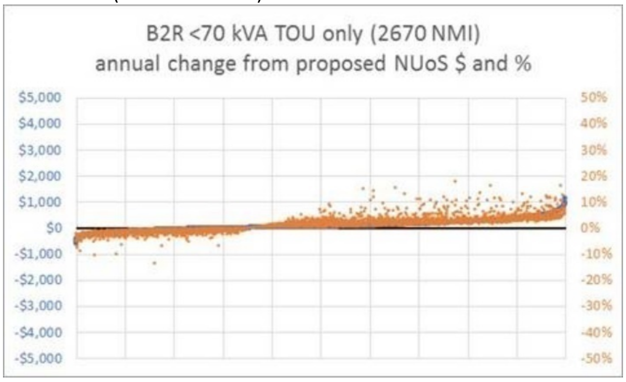
Source: SA Power Networks analysis

Figure 17.55: Small business - Customer impact in Single Rate tariff customers (greater than 70kVA)



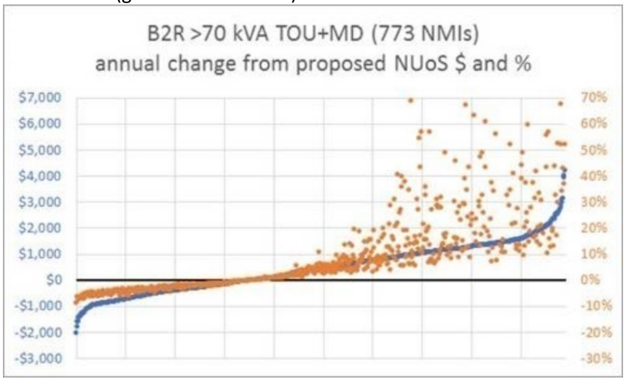
Source: SA Power Networks analysis

Figure 17.56: Small business - Customer impact in Two Rate tariff customers (less than 70kVA)



Source: SA Power Networks analysis

Figure 17.57: Small business - Customer impact in Two Rate tariff customers (greater than 70kVA)



Source: SA Power Networks analysis

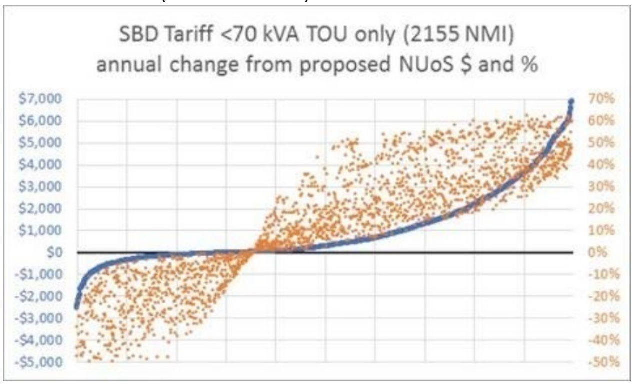
For small business single-rate (BSR) and small business two-rate (B2R) customers (with either less than or greater than 70kVA demand) the proposed tariff structure results in a decrease for many customers but recognises that some customers will experience an increase.

The percentage increase for some customers in this sub-class is quite high. This will be caused by a combination of factors for example,

- the supply charge increasing by approximately $100 pa;
- the anytime demand charge for those customers with high demand but low usage; and
- the peak ToU charge those few customers with high proportion of usage in the peak period of 5:00pm to 9:00pm during November to March. It may be that some of these customers can mitigate the peak ToU impacts through load shifting.

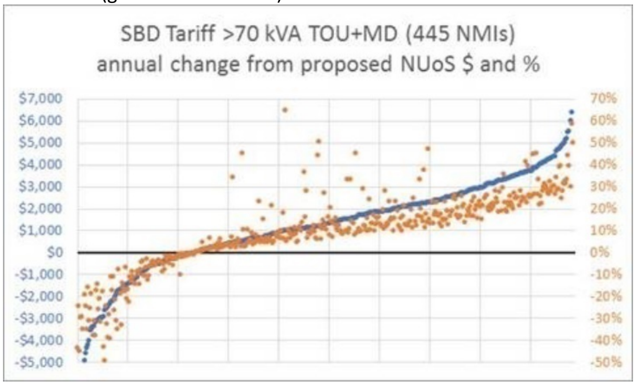
The absolute dollar increase is not as significant as the percentage increase. Given this, we are not proposing any transition arrangements for BSR and B2R customers upon reassignment to small business ToU.

Figure 17.58: Small business – Customer impact in Actual Demand tariff customers (less than 70kVA)



Source: SA Power Networks analysis

Figure 17.59: Small business - Customer impact in Actual Demand customers (greater than 70kVA)



Source: SA Power Networks analysis

Figure 17.60: Small business – Customer impact in Actual Demand tariff customers – Price change in $MWh (greater than 70kVA)

Source: SA Power Networks analysis

Figure 17.61: Small business - Customer impact in Actual Demand customers (greater than 70kVA)

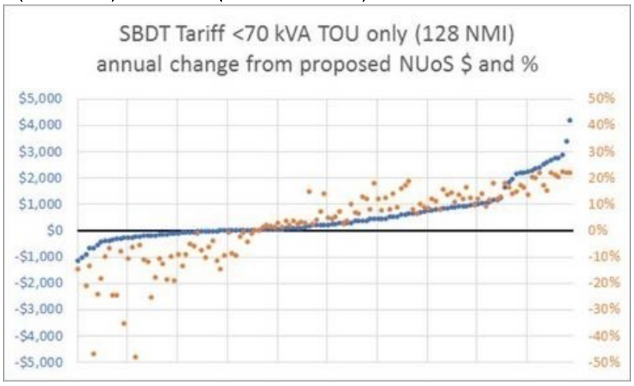
Source: SA Power Networks analysis

For customers <70 kVA, the TOU tariff will provide consistent outcomes. As Figures 17.60 and 17.61 shows many customers face an increase of up to $20/MWh which could be introduced over 2019/20 and 2020/21 tariffs (A transition process over two years at $10/MWh pa). There is a large group of customers in the $20/MWh to $50/MWh who will require between one and two years of transition on the existing SBD tariff.

For customers greater than 70 kVA, the tariff changes comprise both the change in usage price and the use of an anytime demand charge at $15.40/kVA pa. As Figure 17.61 shows, the SBD actual demand tariff had charges for demand during the afternoon and during summer evenings on a monthly basis, but there was no charge for demand outside of those times, ie $0 for anytime demand. Some customers using large amounts of capacity will face a price increase for this component of their usage.

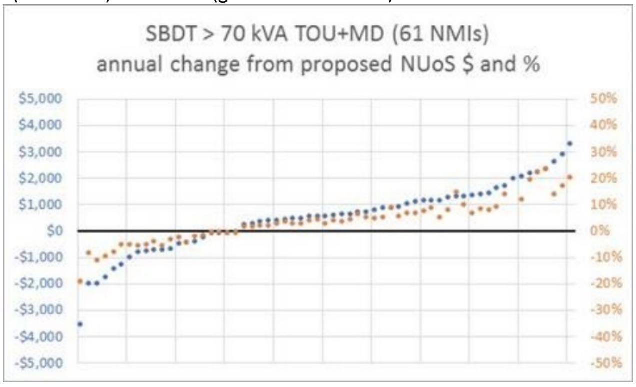
The annual $10/MWh transition for SBD will address some of the increase proposed. Some other transition option may be needed for this anytime demand charge, for those few customers facing increases more than $50/MWh with very high demand but low usage.

Figure 17.62: Small business – Customer impact in Actual Demand (Transition) customers (less than 70kVA)



Source: SA Power Networks analysis

Figure 17.63: Small business – Customer impact in Actual Demand (Transition) customers (greater than 70kVA)

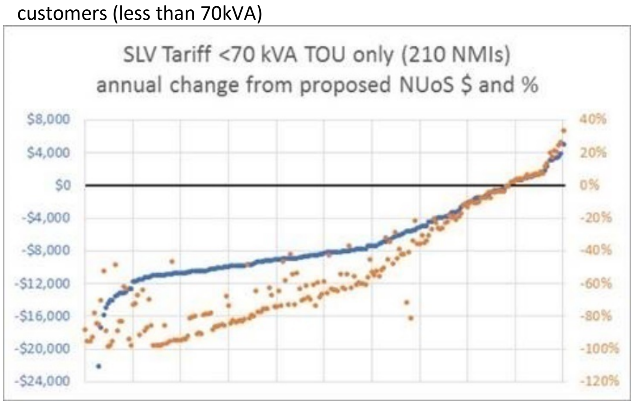


Source: SA Power Networks analysis

The percentage increase for most of the SBD and the SBDT customers (whether less than or greater than 70kVA) is high. Transition to the proposed tariff structure may be required to facilitate the change. This could include several years of annual increases to those tariffs before all the customers can be re-assigned to the proposed tariff.

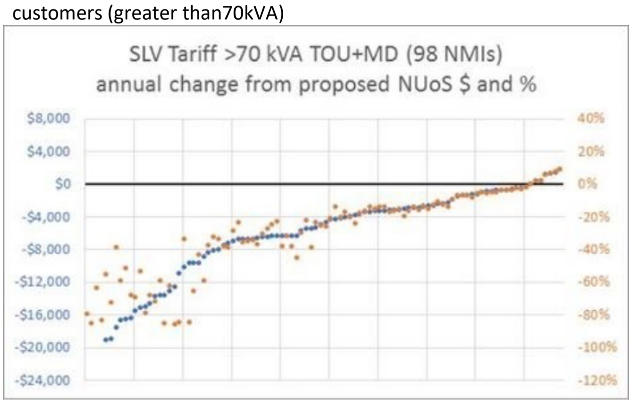
The SBD tariff has very low usage rates compared to the BSR and B2R tariffs. The existing SBD usage rate would need to increase by between 2 cents/kWh and 3 cents/kWh to enable most of the customers to be paying similar amounts to that in the proposed tariff. We propose to increase the usage charge of the SBD tariff by 1 cents/kWh each year for the next four years as a transition measure. Customers will be re-assigned to the proposed tariff progressively on an annual basis according to their individual circumstances.

Figure 17.64: Small business – Customer impact in Agreed Demand customers (less than 70kVA)



Source: SA Power Networks analysis

Figure 17.65: Small business – Customer impact in Agreed Demand customers (greater than70kVA)



Source: SA Power Networks analysis

For the small business agreed demand customers (SLV) the majority of customers will receive a reduction in their network charge. The savings likely to be experienced by the customer will occur through one or more of:

- a July 2020 tariff reassignment;
- the customer electing to use a different tariff prior to July 2020; or
- the customer electing to have an agreed demand reset prior to July 2020.

D.5 Large business

Large business has three tariff classes, but the parameters and considerations are quite similar. It is the rates that will change within the tariff structures between the three classes. Those classes are:

- Large business - low voltage
- Large business - high voltage
- Large business - major business

For each tariff class we have conducted an impact analysis set out in this appendix.

Within large business, we have discussed in section 17.10.5, the locational aspects for CBD (supported by analysis in Appendix C at C.6). The locational aspects of measuring various components will apply to all three large business tariff classes.

D.5.1 Large business Low voltage

Impact of change in large business tariff class

The following charts show the size of price increase (shown in $/MWh) by the size of customer (measured by consumption in MWh pa) for the three existing tariff types – actual demand (**BD**), annual demand (**LV**) and the small subset of annual demand with more than 1000 kVA (**LV 1000**).

Non-CBD Impacts

In Appendix C.6, we have discussed the need for locational pricing for one zone called the CBD. The difference in customer impacts recognises this aspect. The charts below represent impacts for the 'non-CBD' customers.

The charts below (Figure 17.66 and Figure 17.67) demonstrate that most customers on the annual agreed demand (designated by 'LV' in the charts below) will get price reductions.

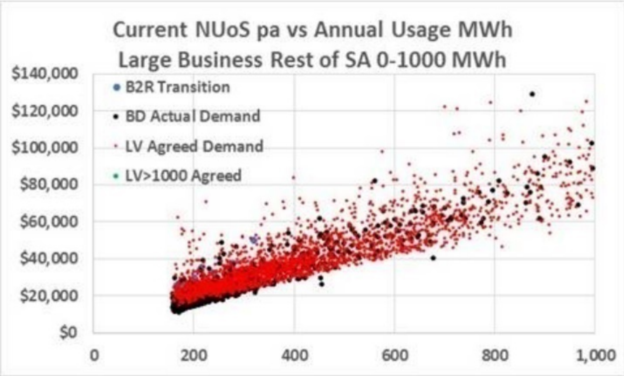
The current annual demand tariffs use an 'agreed' amount, which tends to 'stick' at an historical high in the charging process. To recognise this, and make changes for the benefit of the customer, we have proposed some changes which simplify the outcomes and improve the fairness and equity.

The tariff arrangements we have proposed for the 2020-25 RCP will have two effects:

- The rolling reset (12 months) will ensure that anytime demand and summer peak demand are set at reasonable levels, providing a price reduction, and simplifying the reactive process of recognising the customer's demand.
- The shifting of the peak demand away from 12:00pm – 9:00pm to 5:00pm – 9:00pm means that peak demand has less impact on many business customers. This is offset by an increase in the usage charge applied across the year at peak times (7:00am-9:00pm work days) to recover the balance of business network residual costs. The peak demand signal concentrates on the time of coincident peak on the network, not necessarily the business peak.

The customers on the BD tariff may also have high anytime demands that fall outside of the current BD windows ie 12:00pm – 9:00pm workdays (the BD tariff does not have an anytime demand charge).

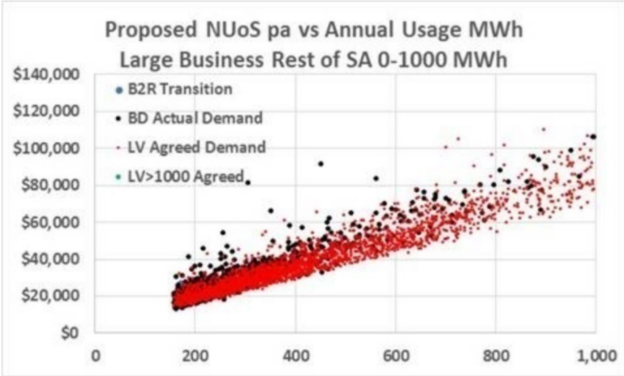
Figure 17.66: Large business LV – Customer impact (current)



Source: SA Power Networks analysis

Note: The (few) customers on transition tariffs are shown in blue. They will receive lower prices from cost-reflective tariffs

Figure 17.67: Large business LV – Customer impact (proposed)



Source: SA Power Networks analysis

The impact of the proposed changes in tariff is demonstrated in a 'propeller chart' for each sub-class of customers within the Large business Low Voltage tariff class.

Charts are presented for three groups according to size for Actual Demand (BD) annual demand (LV):

- Large business LV – BD (actual demand)
- Large business LV – LV (annual demand)
- Large business LV – LV (annual demand) > 1,000 kVA

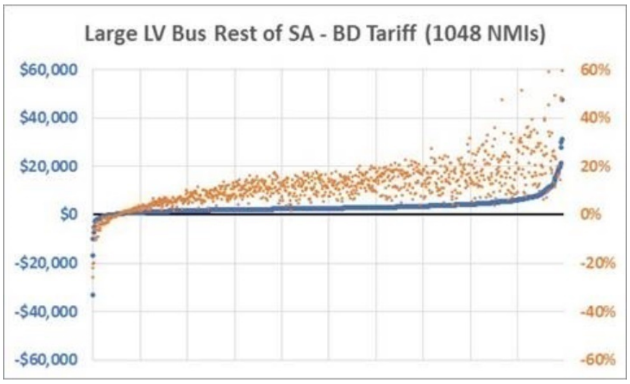
The greatest impact to customers will occur for those with lower consumption but higher demand.

An extra pair of charts is included for the BD (actual demand) analysis which shows the price increase the new tariffs require ($/MWh).

Given the proposal to increase the usage rate of SBD by $10/MWh pa (small business) as a transition measure, we propose to do this as well for large business. The transition shouldn't take as long or be as severe, as the BD tariff is more closely aligned to the costs of large business. However, as the charts show, there are still many customers with more than a $20/MWh price increase.

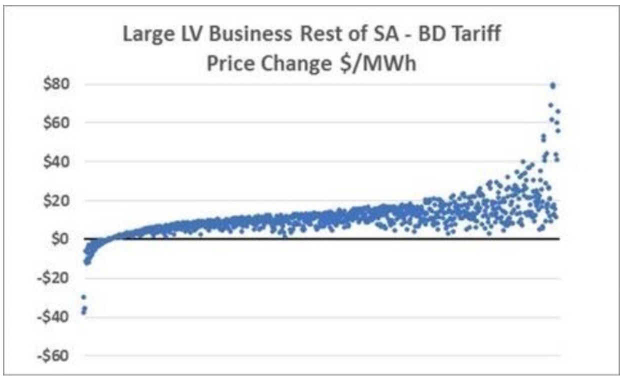
Much of the transition should be achieved by 2020/21 prices as we will have had two years of $10/MWh price increase to usage (2019-20 and 2020-21 price changes). So, any remaining transition issues will only apply for those customers facing more than a $20/MWh price increase.

Figure 17.68: Large business LV – Customer impact in BD actual demand



Source: SA Power Networks analysis

Figure 17.69: Large business LV – $MWh price change in BD actual demand

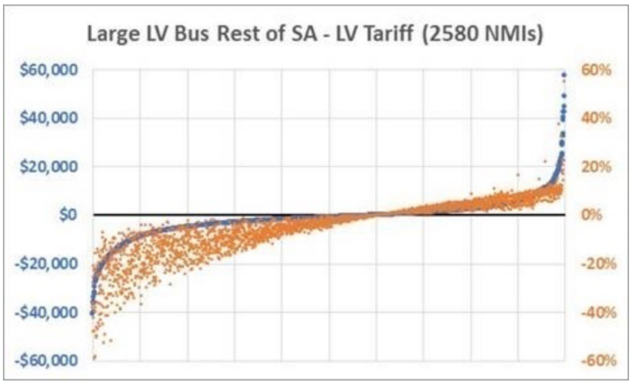


Source: SA Power Networks analysis

The chart on the left (Figure 17.68) shows the range of increases experienced by this group of customers. Modest dollar increases are represented by a range of percentage increases with the majority falling below a 20% increase.

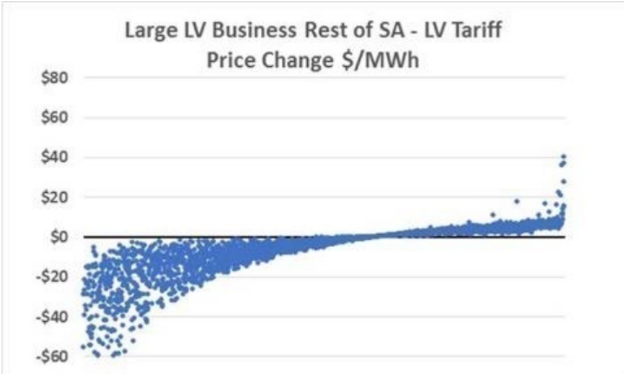
The chart on the right (Figure 17.69) shows that the majority of customers will be covered by the $20/MWh increase as proposed above. This would be proposed by the two-year transitional arrangement.

Figure 17.70: Large business LV – Customer impact in LV annual demand



Source: SA Power Networks analysis

Figure 17.71: Large business LV – $MWh price change in LV annual demand



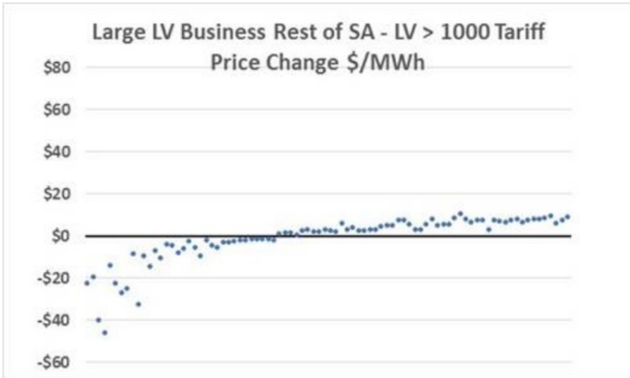
Source: SA Power Networks analysis

In this group of larger Large business LV customers, most of the customer impacts are covered by the $20/MWh increases incorporated into the transition arrangements, leaving few customers to consider by 2020-21.

Figure 17.72: Large business LV – Customer impact in LV annual demand >1,000 kVA

Source: SA Power Networks analysis

Figure 17.73: Large business LV – $MWh price change in LV annual demand > 1,000 kVA



Source: SA Power Networks analysis

The chart for those customers who required more than 1,000 kVA is demonstrated above in **Figure 17.72**.

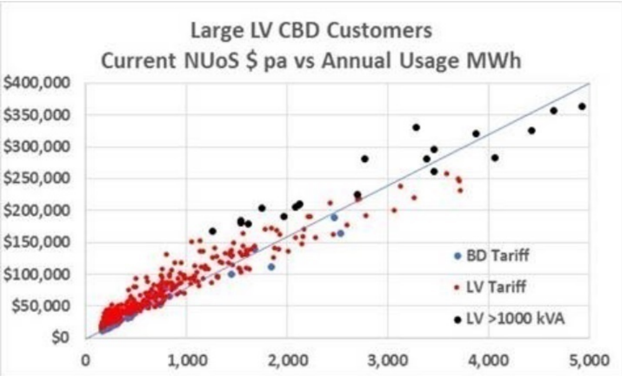
The outcomes for this group of larger consumers is quite different with a significant portion of these customers receiving a price decrease.

Customers in this group were assigned to a tariff which had a declining block price for demand, recognising that larger LV transformers have a lower cost per kVA than smaller LV transformers. Under the new pricing approach proposed, these charges are recovered in the anytime demand charge. An LV 1,000 option has been used which has a lower anytime demand charge but with a higher supply charge. The combination provides the desired price as the size of anytime demand increases.

CBD Impacts

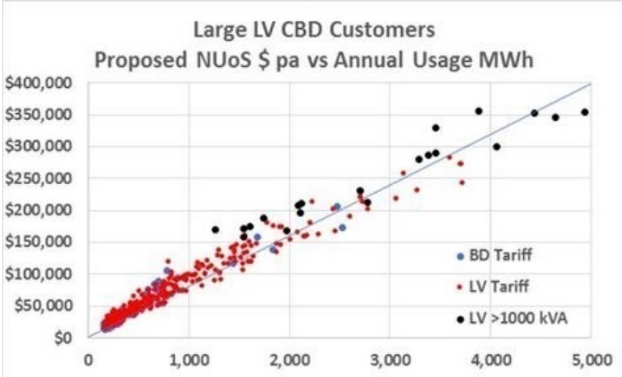
The following analysis identifies the impacts on Large business LV customers in the CBD locational zone

Figure 17.74: Large business LV – CBD Customers Current NUoS $pa vs Annual Usage MWh



Source: SA Power Networks analysis

Figure 17.75: Large business LV – CBD Customers Proposed NUoS $pa vs Annual Usage MWh

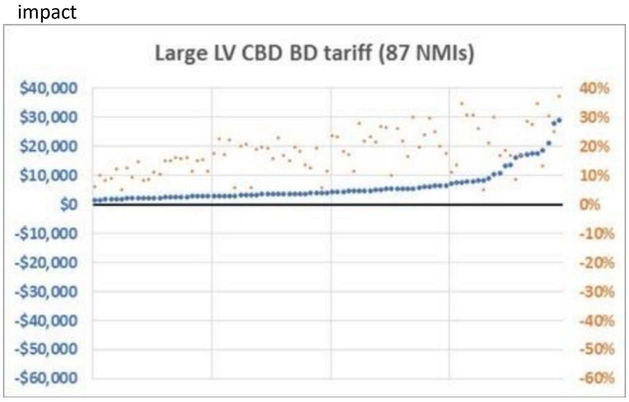


Source: SA Power Networks analysis

Propeller charts and average price change ($/MWh change) – for existing tariffs BD (monthly demand), then LV (annual demand) and LV >1000 kVA (annual demand) are set out below (see **Figure 17.76** to **Figure 17.81**) This explains the impact on these customer groups for Large business in the CBD.

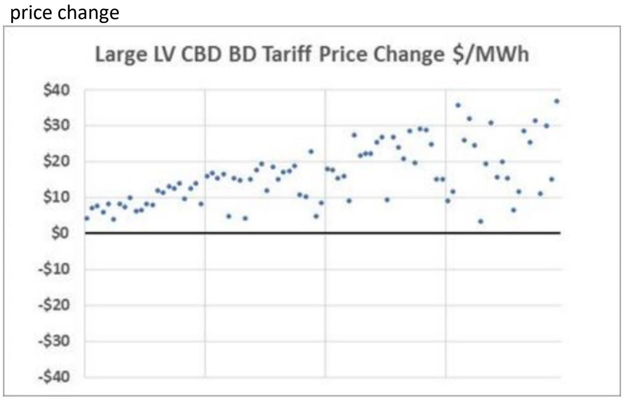
Note that BD (monthly demand) customers have the issue of being currently under-priced. Two years of increases will transition most of the BD customers to the appropriate price level (ie increases in 2019/20 and 2020-21. Some customers will need a transition tariff in 2020-21, and perhaps a handful of customers still on a transition increase in 2021-22.

Figure 17.76: Large business LV – CBD Customer (monthly demand) impact



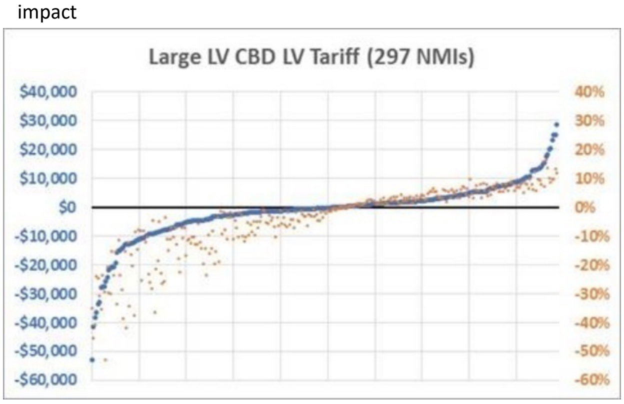
Source: SA Power Networks analysis

Figure 17.77: Large business LV – CBD Customer (monthly demand) price change



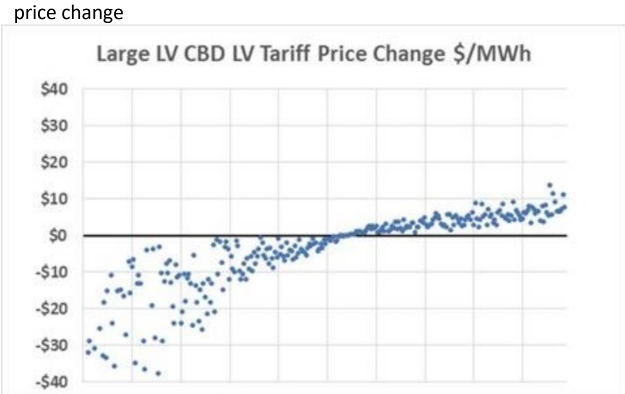
Source: SA Power Networks analysis

Figure 17.78: Large business LV – CBD Customer (annual demand) impact



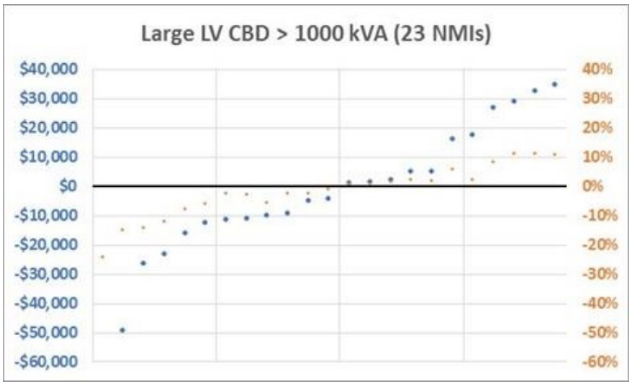
Source: SA Power Networks analysis

Figure 17.79: Large business LV – CBD Customer (annual demand) price change



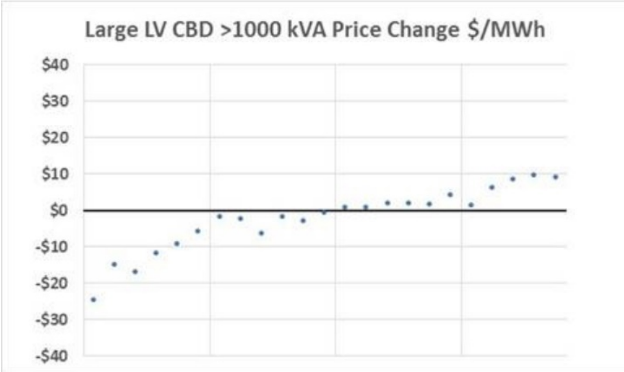
Source: SA Power Networks analysis

Figure 17.80: Large business LV – CBD Customer >1,000 kVA impact



Source: SA Power Networks analysis

Figure 17.81: Large business LV – CBD Customer > 1,000kVA price change



Source: SA Power Networks analysis

D.5.2 Large business High Voltage Tariff Class

Impact of change in Large business High Voltage tariff class

The impact of the proposed changes in tariff for this tariff class is demonstrated in a 'propeller chart' for each sub-class of customers within the Large business High Voltage tariff class.

Charts are presented for three groups according to size:

- Large business HV – annual agreed demand (HV)
- Large business HV – actual monthly demand (**HBD**)
- Large business HV – annual agreed demand < 400 kVA (**HV400**)

We are proposing to simplify the options for this tariff class to the following:

- HV annual demand, with 12-month reset of peak and anytime demands.
- HV actual demand, with 5 months of actual peak HV demand and a 12-month reset of anytime demands.
- The LV actual demand, suitable for those less large businesses (typically less than 500 kVA). The lower supply charge suits those few HV customers with much smaller demands, by not paying more than they would if they were on the Large business LV tariff.

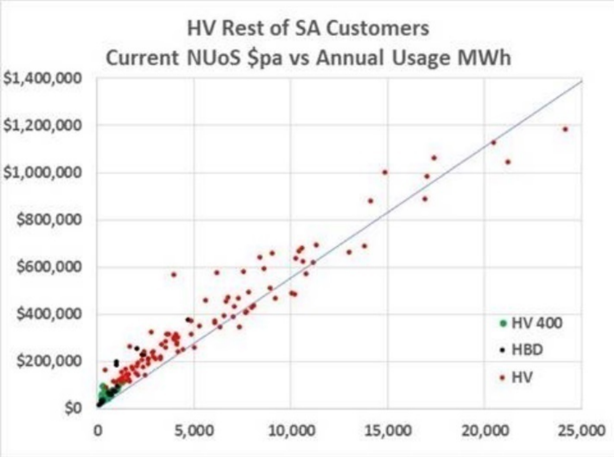
These solutions appear adequate to deal with price transition to the proposed tariffs as there does not appear to be any significant transition issues apart from the HBD tariff having a $10/MWh annual price increase, which manages about 6 customers.

Non-CBD Impacts

The following charts demonstrate outcomes for non-CBD customers. The CBD based Large business HV customers will be shown separately.

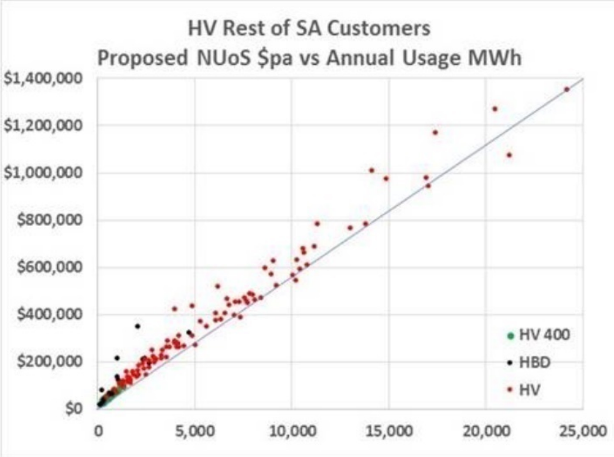
The chart below (Figure 17.82) shows the average price change $/MWh (y-axis) for each existing tariff type (see legend) by annual usage MWh (x-axis).

Figure 17.82: Large business HV – Price impacts for current HV tariff customers



Source: SA Power Networks analysis

Figure 17.83: Large business HV – Price impacts proposed for HV tariff customers

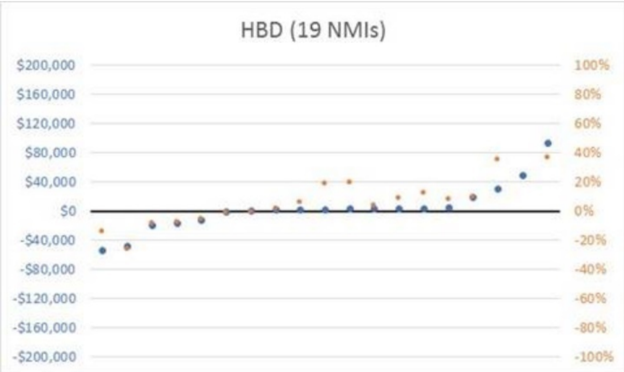


Source: SA Power Networks analysis

Many of the 'agreed monthly demand' HBD customers receive an increase reflecting their high demand and low usage patterns.

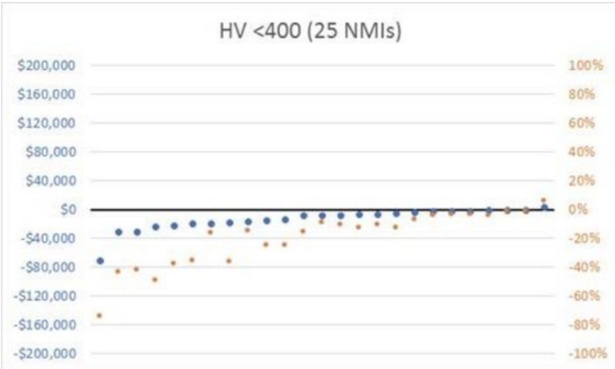
The customer impacts or propeller charts for HV400 (LV priced annual demand), HBD (actual monthly demand) and HV (annual demand) are presented below. The data points are spread out representing the low number of customers in this tariff class as compared with the Large business LV tariff class.

Figure 17.84: Large business HV – Actual monthly demand (HBD)



Source: SA Power Networks analysis

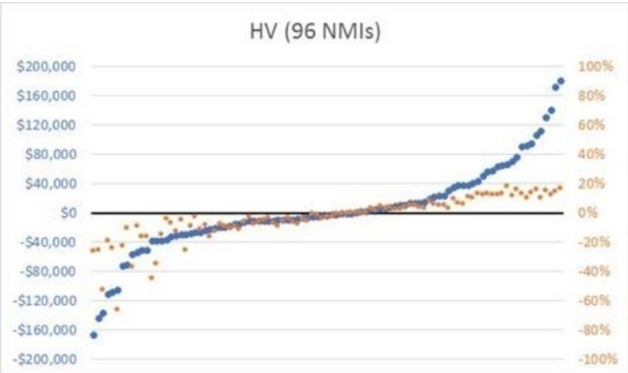
Figure 17.85: Large business HV <400– Actual monthly demand



Source: SA Power Networks analysis

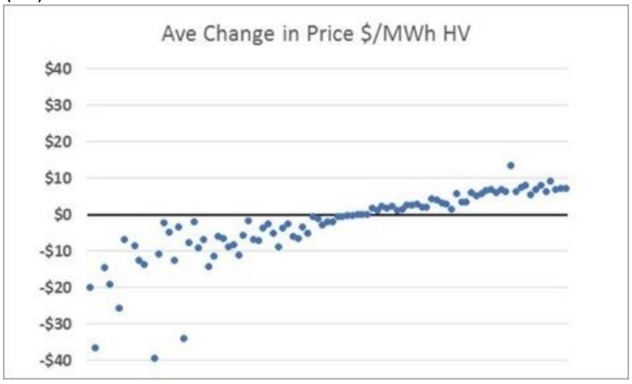
No transition is proposed for the customers on these tariff classes.

Figure 17.86: Large business HV – Customer impact in annual demand (HV)



Source: SA Power Networks analysis

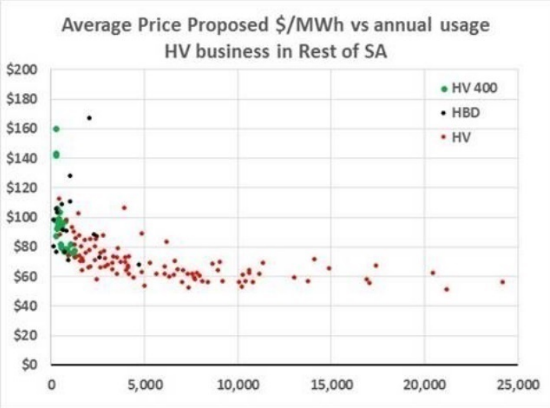
Figure 17.87: Large business HV – Customer impact in annual demand (HV)



Source: SA Power Networks analysis

The chart above shows that the largest customers still get the lowest price under the proposed arrangements.

Figure 17.88: Large business HV – Customer impact in Non-CBD (Summary of proposed arrangements)



Source: SA Power Networks analysis

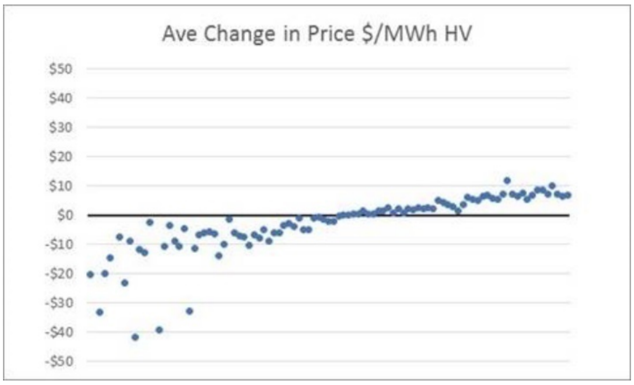
The less large customers (clustering to the left of the chart above) pay a similar price to similar sized customers on LV networks

The average price per MWh is demonstrated below.

Figure 17.89: Large business HV – Average change in price $/MWh for HBD

Source: SA Power Networks analysis

Figure 17.90: Large business HV – Average change in price $/MWh for HV



Source: SA Power Networks analysis

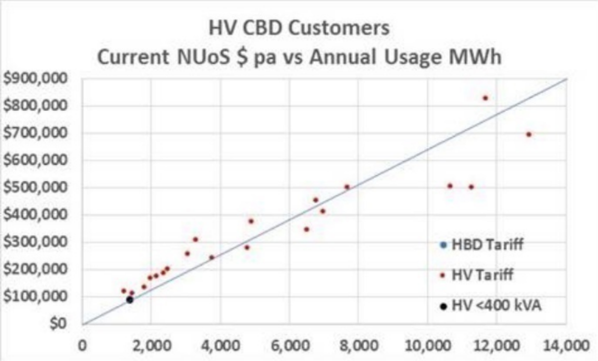
The HV annual demand customers facing large price increases will experience increases in the range of 10% to 20%. Typically, these customers are shopping centres and other loads with good load characteristics that received particularly favourable price outcomes under the existing pricing structures, ie they have very low average prices ($/MWh). The price increase arises from their use of the business network and their contribution to co-incident peak over the 5:00pm to 9:00pm period in summer. The size of the average price increase is less than $10/MWh, and these customers retain a low price, just not as low as it has been in the past. We do not believe this proposed change warrants transition arrangements.

CBD Impacts

The outcomes for Large business - HV customers in the CBD is similar to the outcomes for Large business - LV customers in the CBD, except virtually all customers (20) are on a HV Demand tariff. One customer is on HBD, and one on the LV version (HV400). We have not prepared individual charts for single customer impacts.

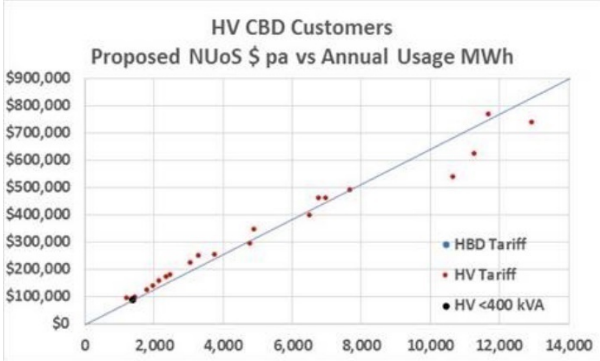
Some of the issues presented by the outliers in the chart below have already been addressed with customers changing their agreed demands.

Figure 17.91: Large business HV – CBD Customers Current NUoS $pa vs Annual Usage MWh



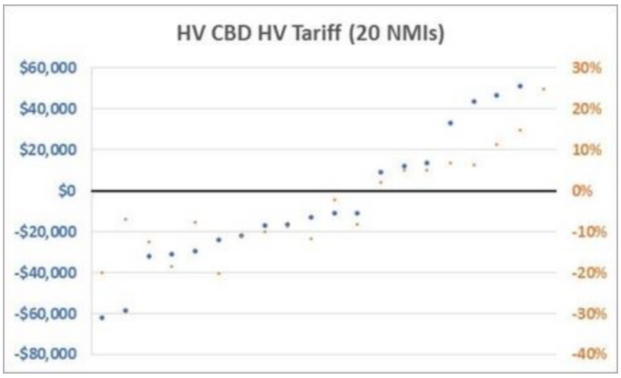
Source: SA Power Networks analysis

Figure 17.92: Large business HV – CBD Customers Proposed NUoS $pa vs Annual Usage MWh



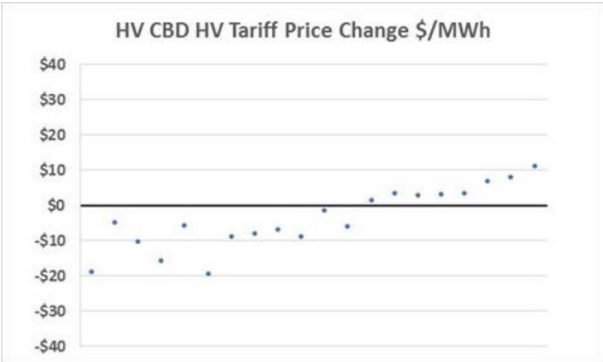
Source: SA Power Networks analysis

Figure 17.93: Large business HV – CBD Customer (HV demand) impact



Source: SA Power Networks analysis

Figure 17.94: Large business LV – CBD Customer (HV demand) price change



Source: SA Power Networks analysis

D.5.3 Major Business High Voltage Tariff Class

The tariffs for major business have varied little from that used in the 2017-20 period. Given the individual nature of the tariff (transmission prices, some distribution fixed charges) and the limited number of customers involved, we do not show any analysis here.

Appendix E. Tariff Philosophies

E.1 Watching brief on future tariffs

Our forecasts are based on a reasonable view of the next five-or-so years and the tariffs proposed respond to the changes which we have experienced to date, and those we can expect to experience in the short to medium term. However, the energy system is changing. New sources of generation and the way customers use the network are changing more quickly than we have experienced in the past.

So, it is likely that our future tariffs will need to respond to changes as they begin to develop. Therefore, we will continue to develop tariffs into the future that will consider the demands and opportunities that they pose to the network including those listed in the following table.

Table 17.31: Future tariff changes

Change	How it might affect future tariffs
Larger exports from customer solar systems	Both the number of solar installations and their size are increasing. A few years ago, it was usual to have a number of smaller solar installations connected each year. We note now that the size of residential installations is increasing as the cost of the solar reduces with technology improvements and volume of production. Further, we have seen an increasing number of commercial installations which are capable of generating hundreds of kilowatts of energy. These large exporters of power can have a significant impact on the local network.
Electric vehicles	The take up of electric vehicles has not been as high as first predicted due to availability and price of electric vehicle products, range and customer preferences. However, customer sentiment in South Australia will change as the world markets respond to global demand, and the electric vehicle product evolves. We expect there will be a time in the future when there will be sufficient electric vehicles to have an impact on the use of charging supported by the network. This represents both a challenge and an opportunity. If electric vehicles were to require charging at the end of the business day, then there will be a significant new load during what we believe will be the peak window between 5:00pm and 9:00pm. However, if charging can occur later in the evening and early morning, then we might be able to shift new load to off-peak times. Further, if smart systems were able to allow the house to draw on some capacity in the vehicle battery during peak times, then the overall peak load could be reduced. It might also be possible for the electric vehicle to charge during the high solar generation period, consuming some of the energy that is available at this time of day and where it is of lower value due to lower net demands. These opportunities will evolve as technology improves to meet customer demand.
Virtual Power Plants	The VPP relates to the ability of customers to pool resources and create a VPP across a number of connections. The South Australian Government is proposing to organise a VPP to improve the use of green energy across the network. We will expect to see the organisation of VPP's in the future that will better manage the export of energy back into the system which may be driven by a combination of network peak or market price of energy.
Embedded networks and micro grids	Microgrids in the future might be organised to exploit the diversified nature of distributed energy, battery storage and the local demands. If organised properly, there is potential that a microgrid might better manage localised peaks and troughs and reduce network costs in the longer term.

Appendix F. Evolution of the customer

F.1 Introduction to the 'evolution of the customer'

The way customers are using our distribution network is changing. In this appendix, SA Power Networks outlines the effect of these changes on the forecast demand and energy volumes for distribution customers.

In the past decade we have seen the influx of a number of disruptive technologies that impact most electricity utilities. Included in these changes are the take-up of solar and energy efficient appliances the former of which has pushed South Australia to the lead in the proportion of customers who have installed residential solar in Australia.

The purpose of this appendix is to determine the outlook for demand and energy over the 2020-25 RCP having regard to the changes in customer take-up of the technologies identified, their demands on the system and the energy consumed. This will influence how we develop charges for the recovery of the allowed revenues set out in our proposal.

F.2 The developments

We outline developments with the following technologies and their impact on underlying demand and energy volumes:

- solar
- battery installations
- electric vehicles

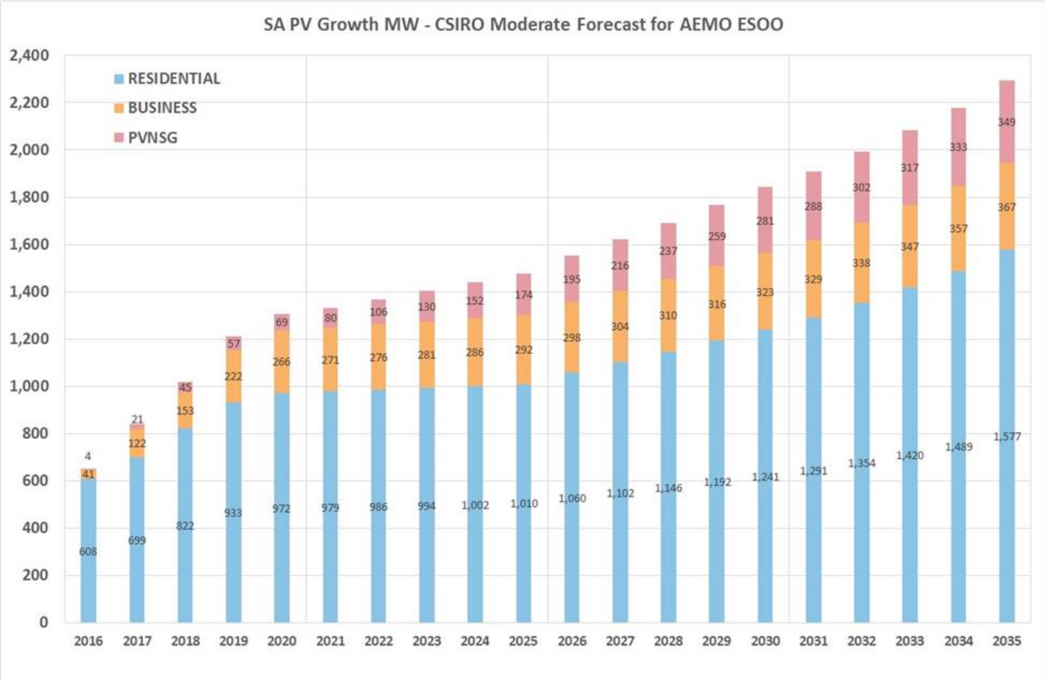
F.2.1 Solar

The impact of solar is changing. In the past, this technology was installed on the roof of the residential customer and we have seen this grow to a position where now more than 30% of our residential customers have solar installed on their roof. This was influenced initially by Government subsidies that supported solar installation then, more recently, with the increases in volumes internationally, the costs of solar installations have decreased allowing more people to access this technology.

More recently we have seen the increase in take-up of commercial solar installed on business premises, predominately for internal use, but with many exporting to our network during non-business hours. Now, we are beginning to see the effects of new, larger solar installations which are designed to export energy to the network as a 'solar PV – non-scheduled generator' (PVNSG).

The outlook for the connection of new solar installations is presented in Figure 17.95, prepared by the CSIRO for the AEMO ESOO.

Figure 17.95: South Australian Growth of Solar by segment (AEMO ESOO)



Source: SA Power Networks Analysis on AEMO Data

The chart above (based on the AEMO ESOO Moderate scenario) reflects the current growth trends through to 2020. A lower expected energy price outcome will reduce growth over the 2020-25 Regulatory Control Period, before returning to a growth in installations across all three sectors post 2025.

By comparison to the 'Moderate' forecast of 1,475MW of solar by 2025, the AEMO ESOO 'Fast' scenario forecasts 1,591MW and the 'Slow' forecasts 1,181MW for the 2025 year. SA Power Networks has applied the 'Moderate' scenario in its forecasts.

For clarification, in the chart above, AEMO's definitions are:

Residential	–	includes solar up to about 10kW per installation, with output used both in-house and partially for export
Business	–	includes typical installation from 10kW to 100kW, with output used within the business and partially for export
Small non-scheduled generation	–	greater than 100kW of installed solar, with the output exported to the network

The small non-scheduled generation does not affect SA Power Network energy volumes forecasts, because all of the output will be carried through the network to customers who will consume the energy. This is different to the Residential and Business installations, where some of the energy will be consumed by the customer direct, reducing network-based energy volumes accordingly. The AEMO energy volumes forecast treats all solar output as negative load (negative energy consumption), so we need to adjust that forecast for any exported energy.

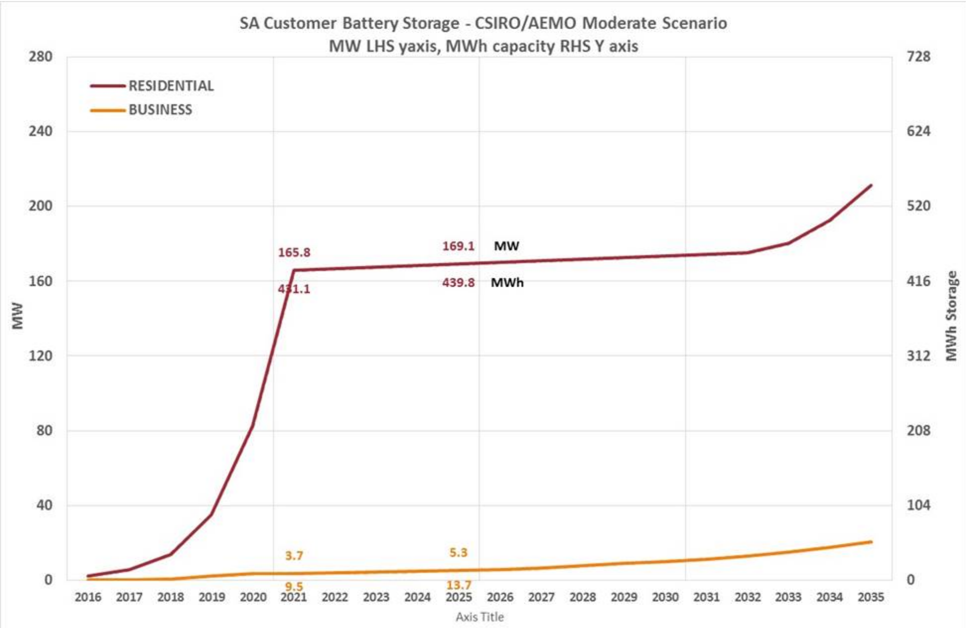
Larger, utility scale Solar Farms are likely to be semi-scheduled generation and connected to the transmission system. These solar installations (do not affect the distribution network) and are not included in this forecast.

F.2.2 Battery installations

The impact of batteries in customer installations is growing significantly, due in part to the availability of more products in the market, but more importantly due to the South Australian Government's subsidy program[24]. This program is forecast to increase the installed capacity of customer battery installations from a modest 100 MWh at the moment to more than 400 MWh by 2021.

The following chart (Figure 17.96) demonstrates the forecast take up of battery storage by the customers as prepared by the CSIRO for AEMO. It demonstrates the significant support by the state government scheme which is expected to end in 2021 followed by a relatively static period to 2030 after which it is expected that the economics of the cost and value of the installations support renewed growth in take-up of this technology by our customers.

Figure 17.96: South Australian Customer Battery Growth (AEMO)



Source: SA Power Networks Analysis on AEMO Data

There is no difference between the 'Moderate', 'Slow' and 'Fast' forecasts as prepared by AEMO. For consistency, SA Power Networks has used the 'Moderate' scenario.

In preparing the forecasts, CSIRO/AEMO have assumed that the batteries will have 2.6 hours of energy for each kW of capacity so a 10 kW battery is assumed to contain 26 kWh of energy. This is important for determining the impact on forecast energy volumes of kWh in the SA Power Networks customer base.

If the average installation is assumed to be 4kW, the forecasts predict that there will be 41,500 battery installations by 2021. This is consistent with the South Australian Government's forecasts in its subsidy program but excludes any growth that might be driven by any other programs such as the AGL/ Housing SA program[25] (a policy of the former South Australian Labour Government).

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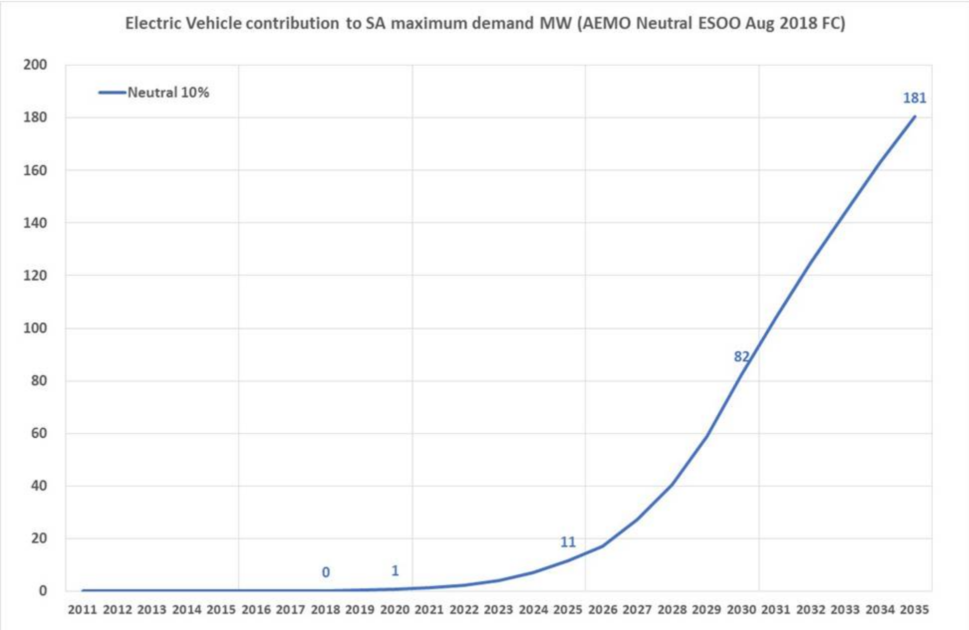
[24] *The South Australian Government announced a battery subsidy scheme where, from October 2018, 40,000 South Australian customers can access a rebate on battery installations receiving up to $6,000 for their investment in new batteries.* http://www.energymining.sa.gov.au/energy_implementation/home_battery_scheme

[25] *The South Australian Government announced a Virtual Power Plant (VPP) program for public housing tenants in 2017-18. The VPP program will provide Housing Trust tenants with an option to apply for solar panels and batteries to be installed on their Housing Trust property. Around 1,100 tenants will be in the trial phases until June 2019.* https://www.sa.gov.au/topics/housing/public-and-community-housing/tenants/virtual-power-plant

F.2.3 Electric vehicles

The take-up of electric vehicles in South Australia is not expected to have any significant impact during the 2020-25 Regulatory Control Period. Figure 17.97 shows the AEMO forecast in the ESOO for electric vehicles in South Australia.

Figure 17.97: South Australian electric vehicles Growth (AEMO)



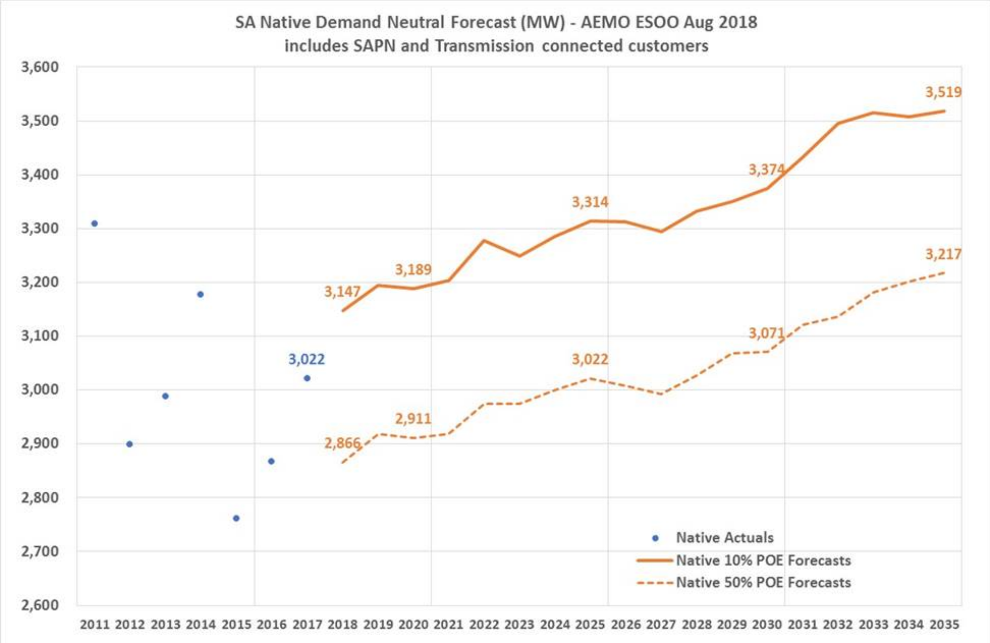
Source: SA Power Networks Analysis on AEMO Data

The cost of the products and the operational range of the current products appear to make this technology unattractive to consumers at the current time. However, in the period post 2026 we expect that the take-up of this technology will require a response from SA Power Networks. We will monitor the development and take-up of this technology, (and how it might be adapted to our customer installations) to assess its impact in the future, however the proposed 2020-25 tariffs should encourage efficient charging should the take-up occur earlier than expected.

F.2.4 Underlying demand

Figure 17.98 demonstrates the AEMO demand forecasts (Neutral Forecast) for South Australia showing both the 10% Probability of Exceedance and the 50% Probability of Exceedance (POE). These charts include all demand in the South Australian system including non-SA Power Networks connected customers (Transmission direct connected customers). The final demand forecasts for SA Power Networks will be proportioned from these AEMO forecasts for the 10% POE to reflect an SA Power Networks forecast demand for the next Regulatory Control Period.

Figure 17.98: South Australian Demand Forecast – AEMO ESOO (August 2018)



Source: SA Power Networks Analysis on AEMO Data

In 2017, AEMO recorded South Australian demand was 3,022 MW. Correspondingly the SA Power Networks total recorded demand for that period was 2,736 MW, representing 90.5% of the AEMO recorded demand. Refer to Appendix Section G.7 below.

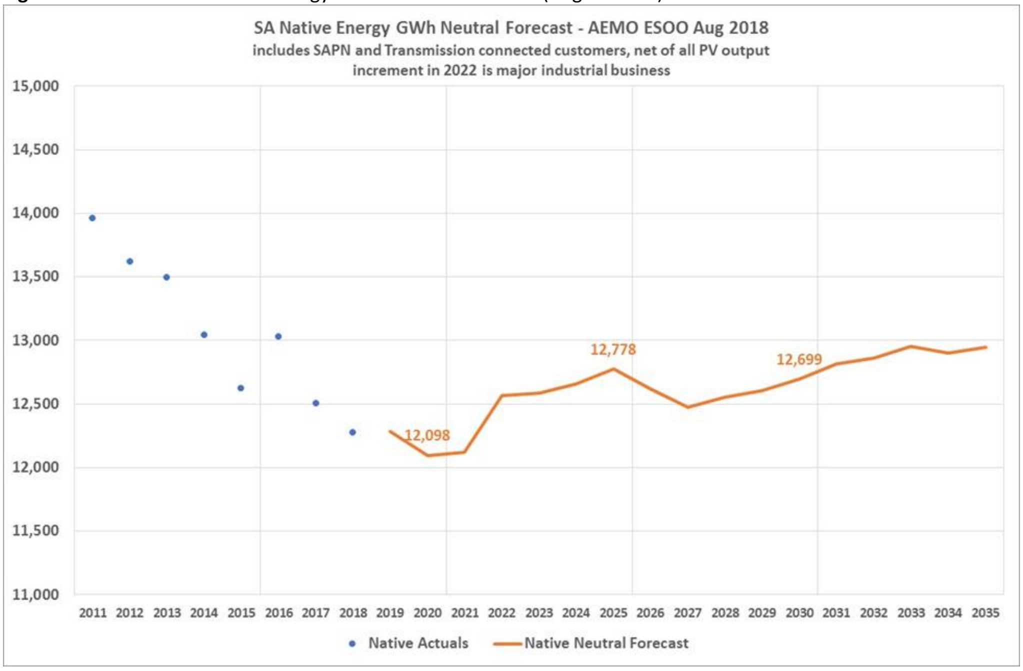
F.2.5 Energy volumes

Figure 17.99 shows the AEMO energy (Neutral) forecasts for South Australia net of all solar output. It includes all SA Power Networks connected customers, and all transmission connected customers.

The Neutral Forecast includes growth in 2022 for a major industrial customer. It should be noted that there has been a substantial reduction in energy volumes in South Australia for the past 8 years and AEMO expects that this decline will be arrested in the next Regulatory Control Period.

The conversion of this AEMO energy forecast into an SA Power Networks energy volumes (MWh) forecast is set out in Appendix Sections G.3 and G.4 below.

Figure 17.99: South Australian Energy Forecast – AEMO ESOO (August 2018)



Source: SA Power Networks Analysis on AEMO Data

F.3 Conclusions - The impact of the 'evolution of the customer' on tariff development

Evolutions	Impact on tariff design
Solar	There is no doubt that the take-up of solar continues to have a significant impact in the South Australian market. Our forecasts for the 2020-25 Regulatory Control Period have considered: • the impact of solar; • its impact on the peak window (refer Appendix C.3); and • the degree to which each type of solar installation affects volumes (MWh)
Battery installations	Battery installations are changing during the current and next regulatory period assisted by government incentives. It is expected that they will have a negative impact on energy volumes in the next Regulatory Control Period. They will convert solar export into in-house use and may assist in reducing peak demand.
Electric vehicles	The take-up of electric vehicles is not expected to have a significant impact on demand or energy volumes in the next 2020-25 Regulatory Control Period. It is expected however to have an impact on the 2025-30 period and SA Power Networks will develop a response for that RCP. Tariffs in 2020-25 will give incentives for efficient electric vehicle charging that avoids the co-incident peak.
Underlying demand	Demand is expected to increase only slightly net of the effect of: • solar; • batteries; and • the effects of energy efficiency, including more efficient air-conditioners progressively replacing the original equipment installed in 1995-2010.

Energy volumes	Energy volumes are expected to remain relatively stable over the next five years net of the effect of customer growth offset by: • solar; • batteries; and • the effects of energy efficiency. Refer Appendix G for discussion on energy volumes forecasting.

Appendix G. Forecasts – Energy, Customers, New Technology and Demand

G.1 Introduction to energy volumes forecasts – AEMO publication

In this appendix, SA Power Networks has set out the energy volumes forecasts including forecasts for residential and business for the period 2020-25. The volumes forecasts have been constructed wherever possible from the AEMO moderate scenario forecasts published in August 2018. The AEMO forecasts are published for the NEM in the ESOO[11].

The ESOO was published using information available at 31 July 2018 and incorporates electricity volume forecasts supplemented with analysis prepared by:

- Strategy Policy Research economic forecasts based on Energy Efficiency Impacts
- CSIRO projections for small scale embedded technologies (such as solar and batteries)
- Energeia projections for electric vehicles

G.2 AEMO ESOO - Growth assumptions

The growth assumptions underpinning the AEMO forecasts are set out below. Discussion is included on:

- population and connection growth
- small scale embedded technologies (such as solar and batteries)
- other AEMO forecasting highlights

G.2.1 Population and connection growth

Population and connection growth in South Australia is lower than New South Wales, Queensland and Victoria as the ESOO Table 4 shows.

Table 4 Forecast connections growth by region – Neutral scenario

	New South Wales		Queensland		South Australia		Tasmania		Victoria	
	Dwelling	Population	Dwelling	Population	Dwelling	Population	Dwelling	Population	Dwelling	Population
2018-19	1.5	1.3	1.8	1.9	1.5	1.0	0.9	0.6	2.1	1.7
2022-23	1.2	1.4	1.8	1.8	0.9	0.9	0.5	0.5	1.6	1.6
2027-28	1.1	1.3	1.6	1.6	0.8	0.8	0.4	0.4	1.4	1.4
2037-38	0.8	1.1	1.4	1.2	0.6	0.6	0.1	0.1	1.2	1.2

Source: AEMO ESOO page 26

G.2.2 Small scale embedded technologies solar growth

Solar is expected to continue to grow in the South Australian market. AEMO recognise that 30% of customers in South Australia already have a solar installation [26].

The number of customers with battery installations is expected to continue to grow. AEMO expects South Australia to have a higher battery forecast over the next five years than the national average, supported by a Government Program to install 40,000 units.[27]

[26] AEMO 2018 National Electricity Market Electricity Statement of Opportunities, August 2018 page 27

[27] *ibid page 27*

G.2.3 Other AEMO highlights

AEMO also included within its forecasts:

- Consumption data in households - whilst households are using more energy than historically through electric appliances, such as home entertainment appliances and space air-conditioning, consumption per household is expected to remain relatively flat due to the offsets created by energy efficiency improvements.

- Electric vehicles - electrification of transport, as projected by CSIRO will likely increase consumption but only after 2030, when electric vehicles are forecast to become cost-competitive with other transport alternatives. AEMO's ESOO is forecasting that electric vehicles could increase the co-incident maximum demand over the coming years. The South Australian demand could increase by 11 MW in 2025; by 82 MW in 2030; and by 181 MW in 2035.

  If electric vehicle recharging can successfully be incorporated within existing network capacity through ToU incentives and customer response, 181 MW of additional demand capacity can be avoided by 2035.

  SA Power Networks' network tariffs have been designed to give customers economic incentives to shift this flexible load away from the current co-incident peak. Customer response will determine what happens to this potential increment in peak demand in the future.

- State based energy efficiency schemes relative to South Australia.

- No substantial change in the timing of minimum demand in South Australia. Whilst the rest of the NEM is moving to experience minimum demands in the middle of the day in the next few years, South Australia has experienced this since 2012.

G.3 Developing the energy volume forecasts for SA Power Networks customers

AEMO has developed an energy volumes forecast for South Australia having regard to the underlying demand, growth in population and connections, the growth in embedded technologies (solar and batteries) and the impact of energy efficiency.

The net result of the analysis produces a forecast state-wide energy volume which is effectively what the generators in the NEM need to deliver to South Australian customers. But this is slightly different to the energy that SA Power Networks needs to deliver to its customers. The AEMO ESOO volumes forecasts need to be adjusted for:

- Recalibration to SA Power Networks measured volumes.
- New export energy which is being delivered to the NEM by the "prosumers" who are exporting energy to the network for use by other customers on our network.

To compare this to historical growth trends in volumes of energy, we have added back:

- The effect of new battery energy consumed in-house.
- The effect of new solar to be installed in the network by our customers.
- The loss of energy volumes due to the effect of energy efficient appliances.

The result of these adjustments will show:

- The AEMO ESOO August 2018 forecast for South Australia.
- The adjusted AEMO ESOO forecast representing the SA Power Networks energy volumes forecasts.

- A representation of where our energy volumes would have been had we not experienced the energy efficiency and embedded technologies on the network.

The resulting energy volumes forecasts are presented in section G.4 of this Appendix below.

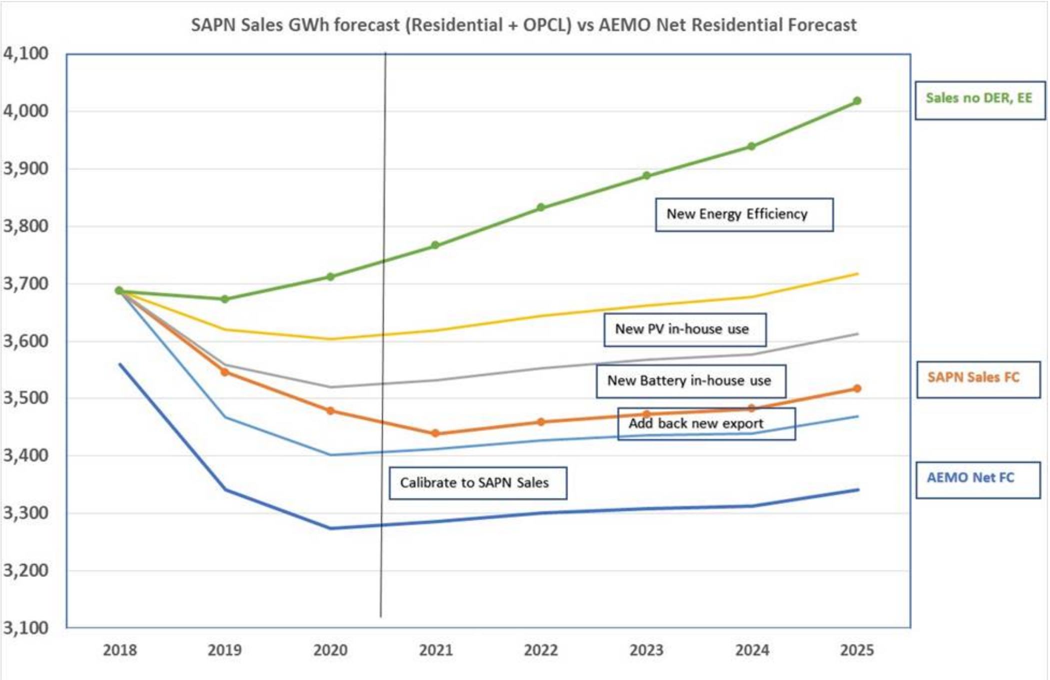
G.4 SA Power Networks volumes forecasts

Energy volumes forecasts are prepared for residential and business customer segments to demonstrate the different effects of growth and disruptive technologies such and energy efficiency, solar and batteries.

G.4.1 Residential energy volumes forecasts

Energy volumes forecasts for residential and Off-peak Controlled Load (OPCL) appliances are set below.

Figure 17.100: South Australian Residential Energy Forecast – Adjusting the AEMO ESOO (August 2018) to calculate the SAPN forecast



Source: SA Power Networks Analysis

In the above chart, energy volumes are adjusted to recalibrate the AEMO net residential energy volumes to SA Power Networks actual energy volumes, then new net exports from new solar are added back to present the forecast volumes for SA Power Networks' customers. As the chart above depicts, there is little change in volumes between the year ended June 2020 and the year ended June 2025. The forecast growth (represented by a net 0.7% annual increase) is the net result of increases in population, connections and demand, offset by energy efficiency and the inhouse use of energy from new solar and batteries.

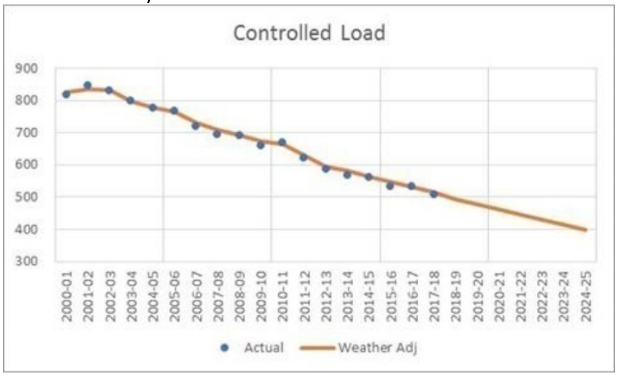
Beyond 2025, the forecasts show a modest increase in the consumption of energy over the next decade to 2035 even with substantial increases in energy efficiency and the offsets caused by new solar installations. Batteries are not forecast to have a material impact on business energy volumes.

The forecasts for energy volumes for the residential and OPCL sectors is set out below with actual historical energy volumes presented for the financial years 2000-01 to 2017-18.

Figure 17.101: SA Power Networks – Residential Volumes History and forecasts in GWh

Source: SA Power Networks analysis

Figure 17.102: SA Power Networks – Off-peak Controlled Load Volumes History and forecasts in GWh



Source: SA Power Networks analysis

G.4.2 Business energy volumes forecasts

Energy Volumes forecasts for Business and Major customers are set below. The AEMO forecast used excludes major industrial customers (some of which are connected to the transmission network). The SA Power Networks forecast distinguishes separately the business and major business energy volumes.

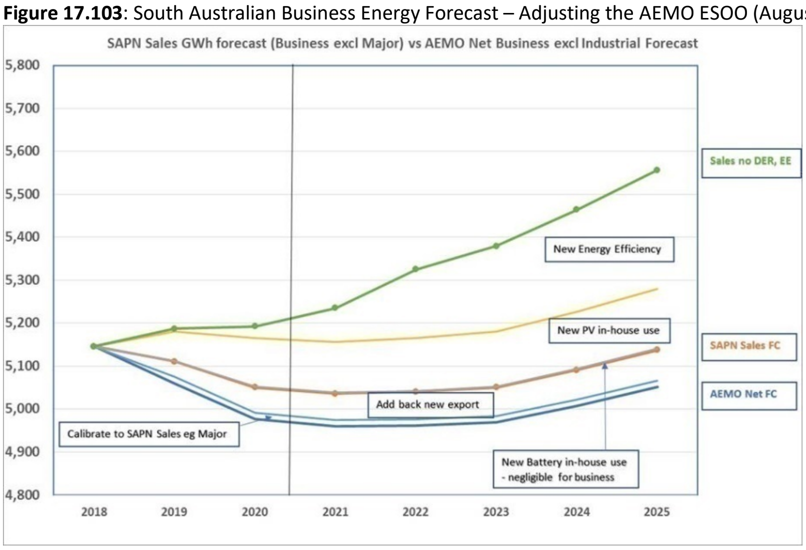
The AEMO forecast is converted to a SA Power Networks business forecast by:

- calibrating to actual energy volumes 2018; and
- adding back any new solar export forecast.

The energy volumes forecasts going forward are lower than historical growth trends because of:

- increased energy efficiency; and
- new solar used in-house.

Figure 17.103: South Australian Business Energy Forecast – Adjusting the AEMO ESOO (August 2018) to calculate the SA Power Networks forecast

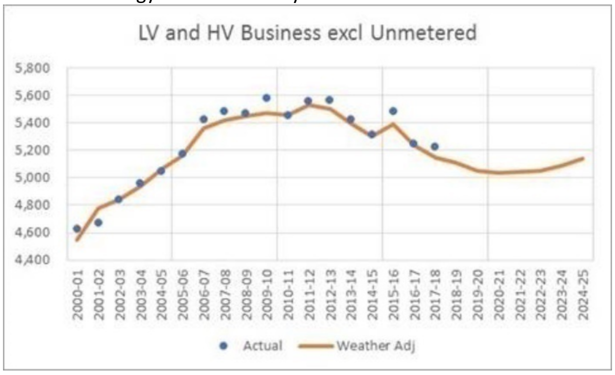


Source: SA Power Networks Analysis

The effects of the adjustments on business are quite different to the residential class of customers. The use of energy and the output of solar is more closely aligned to the business profile and therefore there is proportionally less export (and more in-house use) compared to residential. The effect of batteries is negligible in this customer class.

The forecasts for energy volumes for Low Voltage and High Voltage Business and for Major Business is set out below with actual historical energy volumes presented for the financial years 2000-01 to 2017-18.

Figure 17.104: SA Power Networks – Low Voltage and High Voltage Business Energy volumes History and forecasts in GWh



Source: SA Power Networks analysis

Figure 17.105: SA Power Networks – Major Business Energy volumes History and forecasts in GWh

Source: SA Power Networks analysis

G.4.3 SA Power Networks volume forecasts

Table 17.32: SA Power Networks Volume Forecasts (GWh) by Tariff Class

	Year ended 30 June					
	2020	2021	2022	2023	2024	2025
Residential						
AEMO forecast	3,272	3,282	3,293	3,294	3,286	3,300
Adjustments [1]	206	157	167	179	196	218
SA Power Networks volume forecasts	**3,478**	**3,439**	**3,460**	**3,473**	**3,482**	**3,518**
comprises						
- *Residential*	*3,001*	*2,978*	*3,014*	*3,044*	*3,069*	*3,121*
- *OPCL (Hot Water)*	*477*	*461*	*445*	*429*	*413*	*397*
Business						
AEMO Forecasts	4,977	4,960	4,962	4,969	5,007	5,051
Adjustments [1]	189	191	194	196	199	201
SA Power Networks volume forecasts	**5,166**	**5,151**	**5,156**	**5,166**	**5,206**	**5,253**
comprises						
- *Unmetered*	*115*	*115*	*115*	*115*	*115*	*115*
- *Small business*	*1,385*	*1,381*	*1,383*	*1,385*	*1,396*	*1,409*
- *Large LV Business*	*2,879*	*2,871*	*2,874*	*2,879*	*2,902*	*2,929*
- *HV Business*	*786*	*784*	*784*	*786*	*792*	*799*
Major Business						
AEMO Industrial Forecast [3]	2,772	2,801	3,195	3,203	3,236	3,273
Difference [2]	(1,723)	(1,752)	(2,146)	(2,154)	(2,187)	(2,224)
SA Power Networks volume forecasts	**1,049**	**1,049**	**1,049**	**1,049**	**1,049**	**1,049**
comprises						
- *Zone substation*	*495*	*495*	*495*	*495*	*495*	*495*
- *Sub-Transmission*	*554*	*554*	*554*	*554*	*554*	*554*
Total						
SA Power Networks volume forecasts	**9,693**	**9,639**	**9,664**	**9,687**	**9,737**	**9,819**

Source: AEMO forecasts

Note: Totals may not add due to rounding

1. Adjustments : for calibration, solar and battery export
2. Difference (Major Bus) : ElectraNet customers, less some Business customers SAPN classifies Major
3. AEMO Industrial Forecast : this includes some ElectraNet-connected customers eg Roxby, pipelines

G.5 SA Power Networks customer growth forecasts

The residential customer number forecast has been derived from AEMO's August 2018 ESOO. Residential customer growth averages 1.06% over the period to 2025.

AEMO does not prepare business customer number forecasts, so a SA Power Networks' forecast has been prepared using current business customer numbers and recent growth rates (0.3% pa).

The table below (**Table 17.33**) shows a distinction in the data between:

- active NMIs which is used in energy volumes forecasts; and
- other NMIs which are for either unmetered supply or are for the typical number of NMIs which are inactive at any point in time, eg when a property is churning from one occupant/customer to another, any delay involved in churning from one retailer to another and when a property is disconnected.

The 'no supply customers' have been assumed to increase at the average customer growth rate of 0.98% pa. Abolished NMIs are not included in the table.

The 'all supplies active during the year' represent total NMIs that may be active or inactive during the year (including unmetered supplies). This total is split between feeder types (CBD, urban, short rural and long rural) according to feeder connectivity data.

Table 17.33: Forecasts of customer numbers (based on 2018 AEMO ESOO for residentials)

	Year ended 30 June							
	2018	2019	2020	2021	2022	2023	2024	2025
AEMO Residential	774,419	784,236	794,499	804,774	813,411	820,229	827,013	833,742
SAPN Small business	92,759	93,037	93,316	93,596	93,877	94,159	94,441	94,724
SAPN Large LV Business	5,419	5,435	5,451	5,467	5,483	5,499	5,515	5,532
SAPN HV Business	224	225	226	227	228	229	230	231
SAPN Major Business	26	29	29	29	29	29	29	29
Metered active NMIs	**872,847**	**882,962**	**893,521**	**904,093**	**913,028**	**920,145**	**927,228**	**934,258**
Unmetered supply	4,001	4,040	4,079	4,119	4,160	4,200	4,241	4,282
No supply customers	17,548	17,719	17,892	18,067	18,243	18,421	18,601	18,783
All supplies active during the year	**894,396**	**904,721**	**915,492**	**926,279**	**935,430**	**942,766**	**950,070**	**957,323**

Source: SA Power Networks analysis supported by AEMO residential forecasts

Note. Total may not add due to rounding

G.6 SA Power Networks solar and battery forecasts

The following forecasts for installed solar and batteries is set out below. This information is based on AEMO modelled forecasts for South Australia.

Table 17.34: AEMO Forecasts for solar and battery Installation (CSIRO Moderate Case)

	Year ended 30 June					
	2020	2021	2022	2023	2024	2025
Solar Effective capacity (MW)						
Residential	982.7	991.0	999.4	1,008.1	1,022.8	1,034.2
Business	266.0	270.8	275.8	281.0	286.4	291.9
Total Customer solar	1,248.7	1,261.7	1,275.2	1,289.1	1,309.1	1,326.1
Non Scheduled Generation	68.3	79.3	105.1	129.2	152.4	175.6
Total solar MW	1,317.0	1,341.0	1,380.3	1,418.3	1,461.5	1,501.7
Battery Effective Capacity (MW)						
Residential	82.5	165.8	166.6	167.5	168.3	169.1
Business	3.4	3.7	3.9	4.2	4.7	5.3
Total Battery MW	85.9	169.5	170.5	171.7	173.0	174.4
Battery Effective Capacity (MWh)						
Residential	214.5	431.1	433.2	435.4	437.6	439.8
Business	8.8	9.5	10.1	11.0	12.3	13.7
Total Battery MWh	223.3	440.6	443.3	446.4	449.9	453.4

Source: AEMO forecasts

Note: Rounding may affect the presentation of totals

G.7 Coincident Demand

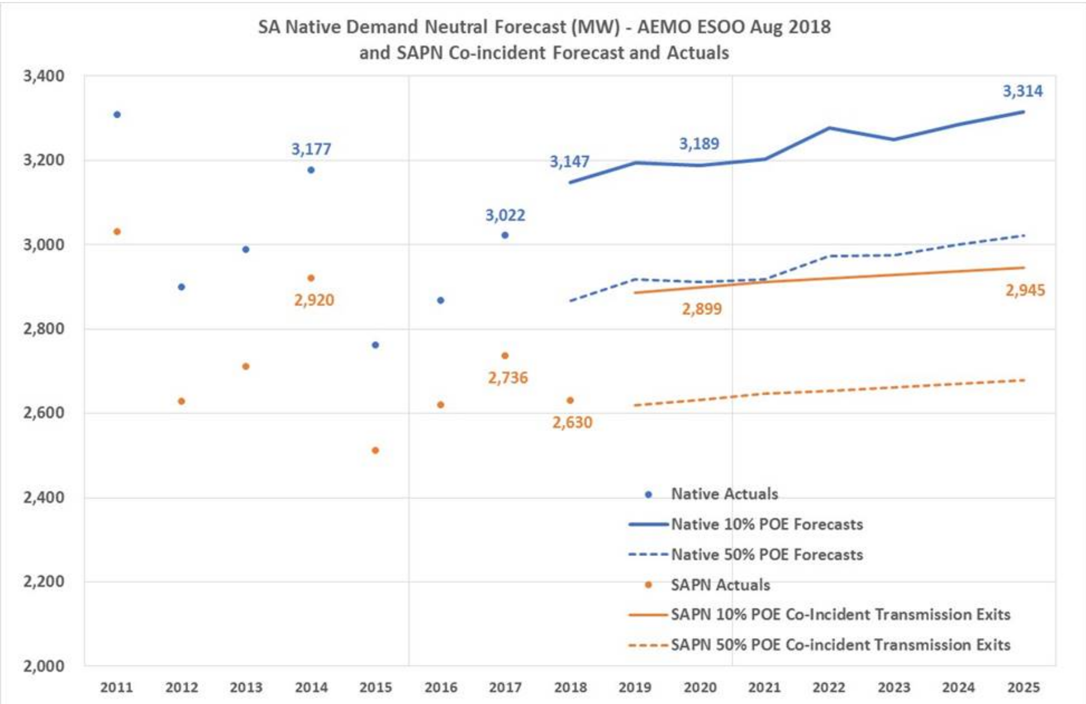
AEMO has prepared a South Australian forecast for co-incident demand, but without any detailed information on the separate contribution by SA Power Networks connected customers and by those customers connected directly to ElectraNet. Demand on SA Power Networks' network represents approximately 90% of total state demand, so the South Australian demand projection provides a sound guide for AEMO's expectations.

As depicted in the following chart (**Figure 17.106**), the AEMO demand forecast has increments in demand from 2022. This is likely to reflect new mining loads and other customers connected directly to ElectraNet's network rather than affecting SA Power Networks' demand.

SA Power Networks expects co-incident demand to be relatively flat over the period to 2025, with peak levels of demand on extreme days (10% POE) continuing as seen in January/February 2014 and January 2019, and 50% POE at the levels of more recent years eg between that seen in January/February 2016 and 2017. Detailed spatial forecasts of demand have been prepared separately by SA Power Networks which forecast the outlook for individual zone substations and transmission exits.

The forecasts for 'Native' demand in the chart below show the historical and forecast for South Australia based on the AEMO analysis. By adjusting for the difference between the 'Native' and the SA Power Networks experienced demand, we can determine the difference represented by the non-distribution related demand and remove that from the AEMO Native forecasts to determine forecast demand on SA Power Networks' network. This approach is carried out for the 10% and 50% Probability of Exceedance forecasts. One final adjustment is to remove the large transmission related load growth in 2022 forecast by AEMO. As mentioned above, this load will not be experienced on the SA Power Networks distribution system.

Figure 17.106: SA Power Networks – South Australian Co-incident Demand Forecasts (Distribution and Transmission customers)



Source: AEMO Forecasts and SA Power Networks analysis

The co-incident demand for the period 2-11 to 2025 can be summarised in the table in the following page.

Table 17.35: Forecasts of co-incident demand (AEMO and SA Power Networks)

	Year ended 30 June														
	2011	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
SA Actual Peak MW	3,308	2,898	2,987	3,177	2,760	2,866	3,022								
SA 10% POE Forecast (AEMO)								3,147	3,195	3,189	3,203	3,278	3,249	3,286	3,314
SA 50% POE Forecast (AEMO)								2,866	2,918	2,911	2,918	2,974	2,975	3,000	3,022
SA Power Networks Actual Peak MW	3,031	2,628	2,711	2,920	2,512	2,620	2,736	2,630							
SA Power Networks 10% POE Forecast (Co-Incident Transmission Exits)									2,886	2,899	2,913	2,921	2,929	2,937	2,945
SA Power Networks 50% POE Forecast (Co-Incident Transmission Exits)									2,620	2,632	2,646	2,654	2,662	2,670	2,678
Difference SA (AEMO) and SA Power Networks Actual Peak	277	270	276	258	248	247	286								
Difference SA (AEMO) and SA Power Networks 10% POE Forecast									309	290	291	357	321	349	369
Difference SA (AEMO) and SA Power Networks 50% POE Forecast									299	279	272	320	313	330	344

Source: SA Power Networks analysis of AEMO and other data

Note that the difference between the SA (AEMO) and SA Power Networks actuals (represented by differences of 248 MW in 2015 to 286 MW in 2017) is reflected in the difference in the initial years between the 10% POE forecasts and 50% POE forecasts.

The difference increases from 2022 when the SA (AEMO) forecasts allow for growth of a new customer connected to the transmission network.

Appendix H. Indicative Pricing Schedule - Alternative Control Services

This appendix sets out our proposed tariff structure for alternative control services (**ACS**) comprising:

- Fee-based and quoted services
- Metering services
- Public Lighting services

ACS are direct control services that are initiated by and/or are directly attributable to specific customers (ie where the cost of the service can be assigned to an individual customer), that are subject to direct regulatory oversight. For the 2020-25 RCP, the AER proposed to classify Type 5 and 6 metering services (legacy metering services), various other metering related services, non-standard connection services, network ancillary services and public lighting services as ACS. We have proposed prices for these services (included in this 2020-25 TSS) to the AER.

The approaches we used to determine the proposed prices for our ACS in the 2020-25 RCP are consistent with those adopted by the AER in other jurisdictions.

Our total revenue for ACS for the 2020-25 RCP is forecast to be $368 million in real June, $2020 dollar terms, based on historical service volumes. Actual revenue realised will vary according to the amount of services provided during the period.

H.1 Fee-based and quoted services

Fee-based and quoted services are customer or third-party initiated services related to our services classified as common distribution services.

These services include the individual fee-based or quoted services in the following service classification groupings:

- network ancillary services;
- metering services – for services other than metering services discussed in section 14.3;
- connection services – for services other than basic premises connections and extensions and augmentations; and
- public lighting.

As an ACS, the full cost of providing fee-based and quoted services is recovered from the customer or third-party who requested, initiated or triggered the service

Our fee-based services charges have been built-up using historical data captured in relation to the provision of each service, with each service having its own specific calculation model. This includes the forecast of the labour, equipment and materials, and contracting services applied in the provision of the service and the time estimated to provide that service.

Quoted services will be charged based on the quantity of labour, materials and contractor services required for the specific work request.

Proposed prices for 2020-25 RCP are largely consistent with those currently charged in the 2015-20 RCP.

Refer Section H.4.1 of this Appendix for the indicative fixed-fee and quoted services price schedule.

H.2 Metering services

From 1 December 2017, all electricity meters that are installed must be a remotely read interval (or 'smart') meter. We remain responsible for the operation, reading and maintenance of existing legacy meters (type 5 and type 6 meters) until they are replaced with a smart meter.

To develop our proposed price caps, we have applied a 'building block approach', where the total revenue reflects the forecast return on capital, return of capital (depreciation), opex, and tax liability. We have used a 'base-step-trend' methodology to determine our opex forecast for the 2020-25 RCP, catering for the expected opex reductions associated with metering contestability.

We propose to retain the existing structure for metering service charges consistent with the previously approved AER methodology. We also propose to simplify our metering service charges for the 2020-25 RCP, with removal of the price variations associated with whole current and current transformer connected metering.

Meter fees in the 2020-25 RCP will be lower than those charged currently, reflecting our reduced metering costs since the commencement of metering contestability.

Refer Section H.4.2 of this appendix for the indicative price schedule for legacy metering services.

H.3 Public Lighting Services

Public lighting services are defined as:

- the operation, maintenance, repair and replacement of public lighting assets;
- the alteration and relocation of public lighting assets; and
- the provision of new public lights.

There are approximately 230,000 public lights installed across our network. Of these, 35,000 (15%) have been upgraded to more energy efficient LEDs, providing improved energy and maintenance outcomes for our customers.

Similar to the calculation methodology that supports the determination of network prices for Standard Control Services, we have applied a building block approach to determine the efficient cost of providing Public Lighting services.

Incorporating the capital and operating costs associated with the provision of these services, the building block approach enables us to continue to support pricing flexibility and customer choice, aligned with our current negotiating framework. Price options vary depending on the various service 'package' options selected by customers. This might include or exclude for example, the maintenance services for the lamp.

Proposed public lighting prices for the 2020-25 RCP have been developed following extensive consultation with councils and other public lighting customers.

Refer Section H.4.3 of this Appendix for the indicative public lighting price schedule.

Further details on ACS are available in Attachment 14 – Alternative Control Services.

H.4 ACS price lists

H.4.1 Fee-based and quoted services price schedule

H.4.1.1 Fee-based services

Table 17.36: Proposed fee-based charges ($June 2020)

Service Group	Service	Service Description	Fee code	2020/21	2021/22	2022/23	2023/24	2024/25
Network Ancillary Services – customer and third-party initiated services related to common distribution services								
Access permits, oversight and facilitation	Network access management fee	Management of access request where under ½ day of planning is required.	NDS 381	$508	$508	$508	$508	$508
	Network access management fee - cancellation	Cancellation of network access permit within 2 full business days of confirmed date.	NDS 429	$508	$508	$508	$508	$508
Network safety services	Temporary line insulation (eg tiger tails)	Temporary insulation of LV mains, eg to erect and remove 'Tiger Tails' on LV mains.	NDS 371	$838	$843	$850	$856	$861
Inspection and auditing services	Site Inspection	Site inspection to determine nature of the requested connection service < 2 hrs.	NDS 398	$328	$328	$328	$328	$328
	Re-inspection for compliance	Re-inspection of an asset issued with a non-compliance notice (including travel time) – up to 3 hours normal time.	NDS 345	$393	$393	$393	$393	$393
	Re-inspection for compliance > 3hrs	Re-inspection of an asset issued with a non-compliance notice – hourly rate after 3 hours normal time.	NDS 346	$131	$131	$131	$131	$131
	Re-inspection for compliance – after hours	Re-inspection of an asset issued with a non-compliance notice – hourly rate after hours.	NDS 347	$131	$131	$131	$131	$131
Customer requested provision of electricity network data	Location of underground mains – provision of plans from office	Location of underground mains at the request of a customer – provision of plans from the office (no site visit required).	NDS 373	$133	$134	$136	$137	$139
	Asset information request	Provision of asset information relating to condition, rating or available capacity to engineering consultants and electrical contractors and the supply of GIS information to	NDS 377	$164	$164	$164	$164	$164

Service Group	Service	Service Description	Fee code	2020/21	2021/22	2022/23	2023/24	2024/25
		customers or authorities < 1 hours work per request.						
	Asset info request - Ground level transformers (site visit to open and visually see equipment)	Confirmation of available equipment in ground level transformers where the door needs to be opened by a SA Power Networks employee.	NDS 379	$328	$328	$328	$328	$328
	Swing & Sag Calculations up to 11kV	Project management and survey work undertaken to prepare and issue a swing and sag calculation letter for the customer – up to 11kV.	NDS 419	$1,989	$1,989	$1,989	$1,989	$1,989
	Swing & Sag Calculations > 11kV	Project management and survey work undertaken to prepare and issue a swing and sag calculation letter for the customer - > 11KV.	NDS 428	$2,646	$2,646	$2,646	$2,646	$2,646
Metering services—activities relating to the measurement of electricity supplied to and from customers through the distribution system (excluding network meters)								
Auxiliary metering services (type 5 to 7 metering installations)	Meter test – single phase	Customer requested meter test where SA Power Networks is the Metering Coordinator (MC) and when a test is required due to high account or a subsequent incorrect functioning solar installation.	NDS 356	$123	$125	$126	$128	$129
	Meter test – additional single-phase meter	Testing of each additional single-phase meter in conjunction with single phase meter test.	NDS 357	$0	$0	$0	$0	$0
	Meter test – three-phase	Customer requested meter test where SA Power Networks is the Metering Coordinator (MC) and when a test is required due to high account or a subsequent incorrect functioning solar installation.	NDS 358	$123	$125	$126	$128	$129
	Meter test – additional three phase meter	Testing of each additional three-phase meter in conjunction with single phase meter test.	NDS 359	$0	$0	$0	$0	$0
	Solar installation enquiry – single phase	Customer requests SA Power Networks to attend a single phase solar installation which is not functioning correctly, and it is determined by the SA Power Networks' personnel that the problem is a result of the customer's solar installation being incorrectly set / malfunctioning.	NDS 360	$123	$125	$126	$128	$129
	Solar installation enquiry – three-phase	Customer requests SA Power Networks to attend a three-phase solar installation which is not functioning correctly, and it is determined by the SA Power Networks' personnel that the problem	NDS 362	$123	$125	$126	$128	$129

Service Group	Service	Service Description	Fee code	2020/21	2021/22	2022/23	2023/24	2024/25
		is a result of the customer's solar installation being incorrectly set / malfunctioning.						
	Meter inspection fee	Request to complete physical inspection where SA Power Networks is the Metering Coordinator (MC) due to suspected meter tampering, equipment damage, or requested by the customer or their retailer.	NDS 364	$57	$58	$58	$59	$60
	Meter inspection fee – each additional meter	Request to complete physical inspection where SA Power Networks is the Metering Coordinator (MC) - each additional meter.	NDS 365	$0	$0	$0	$0	$0
	Special meter read visit – normal hours	A special meter reading visit occurs when a customer requests a check read or special read at premises.	NDS 386	$12	$13	$13	$13	$13
	Special meter read visit – after hours	A special meter reading visit occurs when a customer requests a check read or special read at premises (where after-hours visit is requested).	NDS 387	$87	$88	$89	$90	$91
	Special meter read visit – request cancellation	Special meter reading visit which is subsequently cancelled.	NDS 388	$11	$12	$12	$12	$12
	Meter read – subsequent attempt	Subsequent attempts to read a meter after reasonable attempt has been made but has been unsuccessful due to access difficulties.	NDS 389	$12	$13	$13	$13	$13
Connection services—services relating to the electrical or physical connection of a customer to the network								
Connection application and management services	Temporary supply - overhead or underground on existing pole	Provision of a temporary over to under service on an existing stobie pole that is located up to 25 metres from the customer's property boundary on the mains side of the street.	BCS 141	$1,153	$1,157	$1,163	$1,168	$1,172
	Temporary supply - Existing pit/pillar	Provision of a temporary service from an existing low voltage service pit/pillar that is located up to 25 metres from the property boundary.	BCS 145	$476	$479	$482	$485	$487
	Permanent abolishment of LV service	Request for permanent abolishment of the LV supply provision (this does not include the removal of additional distribution assets ie poles and transformers)	NDS 301	$633	$638	$642	$647	$651
	Temporary disconnect and reconnect - customer	Requests for a temporary disconnection and reconnection, requiring a line truck attendance.	NDS 302	$1,051	$1,059	$1,068	$1,077	$1,084

Service Group	Service	Service Description	Fee code	2020/21	2021/22	2022/23	2023/24	2024/25
		Requests for a temporary disconnection and reconnection, requiring a single person crew attendance.	NDS 330	$464	$466	$469	$472	$474
	Excess kVAr incentive	The Excess kVAr incentive charge is applied to each excess kVAr required over and above the implied kVAr allowance provided in the South Australian Electricity Distribution Code to meet a customer's agreed maximum demand on their recorded power factor at the time of their Actual Maximum Demand. The charge is applied to customers currently assigned to a network demand tariff who are not code compliant with respect to power factor at the time of their Actual Maximum Demand requiring greater than 10kVAr of correction.	NDS 366	$50	$50	$50	$50	$50
	Connections specification fee - $0-$100k project	Work undertaken in preparing and issuing the specification including one site visit for customer extension works. Project value $0 - $100k based on contestable value of project.	NDS 340	$3,280	$3,280	$3,280	$3,280	$3,280
	Connections specification fee - $101k-$200k project	Work undertaken in preparing and issuing the specification including one site visit for customer extension works. Project value $101k - $200k based on contestable value of project.	NDS 341	$5,740	$5,740	$5,740	$5,740	$5,740
	Priority or out of hour appointment – less than 3 hours	Provision of a priority connection at the customer's request. Work will be undertaken out of hours or during normal hours in which case another job will be done after hours to accommodate the requested connection date.	NDS 401	$202	$202	$202	$202	$202
	Retailer fee - disconnection & reconnection – Disconnection at meter	Disconnection of supply (if a service order is subsequently cancelled by the retailer, the same fee applies).	NDS 403	$87	$88	$89	$90	$91
	Retailer fee - disconnection & reconnection – reconnection at meter	Reconnection of supply (if a service order is subsequently cancelled by the retailer, the same fee applies).	NDS 404	$87	$88	$89	$90	$91
	Retailer fee - disconnection & reconnection – reconnect meter after hours	Reconnection of supply after hours (if a service order is subsequently cancelled by the retailer, the same fee applies).	NDS 405	$87	$88	$89	$90	$91

Service Group	Service	Service Description	Fee code	2020/21	2021/22	2022/23	2023/24	2024/25
	Embedded generation firm offer - >30kW-200kW	Work undertaken for the network analysis, preparing and issuing an offer letter, contract and associated commissioning for the customer's embedded generation system.	NDS 427	$3,743	$3,743	$3,743	$3,743	$3,743
	Temporary disconnect and reconnect - retailer	Requests for a temporary disconnection and reconnection, requiring a line truck attendance.	NDS 430	$1,054	$1,062	$1,071	$1,080	$1,088
		Requests for a temporary disconnection and reconnection, requiring a single person crew attendance.	NDS 431	$464	$466	$469	$472	$474
Enhanced connection services	Alter/relocate/replace of overhead/underground service	Customer request for relocation / alteration or replacement of an existing overhead or underground service.	BCS 106	$1,290	$1,295	$1,302	$1,308	$1,313
	Multiphase upgrade - O/under or O/head	Provision of an over to under service on an existing low voltage stobie pole or an overhead service from an existing low voltage stobie pole and the requested number of phases are available.	BCS 109	$1,310	$1,316	$1,323	$1,329	$1,335
	Multiphase upgrade - O/under or O/head	Connection provided from an existing suitable low voltage service pit / pillar and the requested number of phases are available at the service point.	BCS 110	$549	$553	$557	$560	$563
	Multiphase upgrade - existing pit/pillar	Provision of an over to under service on an existing low voltage stobie pole or from an existing service pit/pillar that is located up to 25 metres from the customer's property boundary on the same side of the street and the requested number of phases are available.	BCS 111	$1,290	$1,295	$1,302	$1,308	$1,313

H.4.1.2 Quoted Services

We provide a range of non-standard services on a quoted basis including:

- access permits, oversight and facilitation;
- sale of approved materials or equipment;
- notices of arrangement and completion notices;
- network safety services (eg high load escorts);
- customer requested planned interruption;
- attendance at a customer's premises to perform a statutory right where access is prevented;
- inspection and auditing services;
- provision of training to third parties for network related access;
- authorisation and approval of third party service providers' design, work and materials;
- security lights;
- customer initiated or triggered network asset relocations / re-arrangements;
- customer requested provision of electricity network data;
- third party funded network alterations or other improvements;
- auxiliary metering services (type 5 – 7 metering installations);
- meter recovery and disposal – type 5 and 6 (legacy meters);
- third party requested outage for the purposes of replacing a meter;
- emergency maintenance of failed metering equipment not owned by SA Power Networks;
- standard and negotiated connection services (premises connections, excluding extensions and augmentations);
- connection application and management services (eg, connection point alterations, temporary supply, technical / engineering studies, specification fees, specification re-compliance, works / design compliance / network infrastructure connection re-appointments, and pole top disconnections / reconnections);
- enhanced connection services (large embedded generators (>200kW)); and
- public lighting.

H.4.1.3 Quoted services formula

We propose to apply the following formula for our quoted services:

Price = Labour + Contractor Services + Materials + Margin

Where:

Labour consists of all labour costs directly incurred in the provision of the service which may include labour on-costs, fleet on-costs, and overheads. Proposed labour rates are set out in section H.4.1.4 below.

Contractor Services reflect all costs associated with the use of the external labour including overheads and any direct costs incurred. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.

Materials reflect the cost of materials directly incurred in the provision of the service, material on-costs and overheads.

Margin is equal to 6 per cent of the total costs of labour, contractor services and materials.

H.4.1.4 Quoted service labour rates

Proposed labour rates applicable for quoted services are contained in **Table 17.37**. Penalty rates will be applicable to all after hours work.

Table 17.37: Proposed labour rates applicable to quoted charges ($June 2020)

Labour Code	Description	2020/21	2021/22	2022/23	2023/24	2024/25
Admin	Administrative Officer	90.84	91.75	92.67	93.60	94.53
PM	Project Manager	157.83	159.41	161.00	162.61	164.24
FW	Field Worker	125.65	126.90	128.17	129.46	130.75
Tech	Technical Specialist	163.07	164.70	166.35	168.01	169.69
Eng	Engineer	152.33	153.85	155.39	156.94	158.51
Seng	Senior Engineer	184.19	186.03	187.89	189.77	191.66

H.4.2 Metering services price schedule

Indicative price schedule for legacy metering services – effective from 1 July 2020

SA Power Networks will charge a legacy metering service charge for all NMI's where we provide legacy metering services. Charges will be applied as a fixed daily charge on a 'per NMI' basis.

There are four different combinations of legacy metering service charges possible:

- **Existing customers using SA Power Networks' meters that were installed prior to 1 July 2015** - These customers continue to pay the capital and non-capital charges;
- **Existing customers using SA Power Networks' meters that were installed after 1 July 2015** - These customers will have incurred an upfront capital charge and will continue to pay the non-capital charge;
- **Existing customers using SA Power Networks' meters at 30 June 2015 with meters subsequently replaced by 3rd party meters** – These customers will continue to pay the capital charge and will cease paying the non-capital charge. This will apply to all metering upgrades and replacements undertaken by retailers under metering contestability arrangements post December 2017; and
- **New customers after 1 July 2015 with 3rd party meters installed** – These customers are not liable for any annual metering charges to SA Power Networks. From December 2017 (metering contestability commencement), where a new customer connects to the network the retailer will arrange metering.

Table 17.38: Proposed annual metering service charges ($nominal)

		2020/21	2021/22	2022/23	2023/24	2024/25
Legacy metering service charge	Non-capital	13.41	14.22	15.13	16.11	17.15
	Capital	10.01	10.00	9.98	9.95	9.92
	Non-capital and capital	23.42	24.22	25.11	26.06	27.08

H.4.3 Public Lighting price schedule

Table 17.39: Proposed annual public lighting charges – LED lights ($June 2020)

Category	Service Description	Option	2020/21	2021/22	2022/23	2023/24	2024/25
All Lights	Energy Only	All lights	3.06	3.09	3.13	3.17	3.20
P Category	CLER	Sylvania StreetLED 17W	16.17	16.28	16.42	16.67	16.78
		Sylvania StreetLED 25W	16.30	16.42	16.55	16.81	16.92
		Sylvania StreetLED 18W	16.69	16.80	16.94	17.21	17.33
		Advanced Edge40 D350P 46W	16.20	16.31	16.44	16.70	16.81
		Pecan SAT-48S 44W	16.20	16.31	16.44	16.70	16.81
		Kensington 17W PT	21.32	21.47	21.64	22.07	22.21
		Kensington 34W PT	21.32	21.47	21.64	22.07	22.21
		Sylvania B2001 34W	16.20	16.31	16.44	16.70	16.81
		Sylvania StreetLED 18W	16.20	16.31	16.44	16.70	16.81
		Pecan NXT-24S 450 35W	19.54	19.68	19.84	20.21	20.34
		Alt Ledway 30 D350 39W	16.20	16.31	16.44	16.70	16.81
		Alt Ledway 20 D350 26W	16.20	16.31	16.44	16.70	16.81
		Pecan NXT-12S 525 20W	19.54	19.68	19.84	20.21	20.34
		Pecan NXT-24S 350 29W	19.54	19.68	19.84	20.21	20.34
		Sylvania StreetLED 17W - Regional	16.20	16.31	16.44	16.70	16.81
		Bourke Hill 22W LED	19.89	20.03	20.19	20.58	20.71
	PLC	Sylvania StreetLED 17W	57.93	58.74	59.19	59.84	60.36
		Sylvania StreetLED 25W	58.05	58.87	59.32	59.97	60.49
		Sylvania StreetLED 18W	58.42	59.23	59.68	60.35	60.88
		Advanced Edge40 D350P 46W	57.95	58.77	59.21	59.87	60.39
		Pecan SAT-48S 44W	57.95	58.77	59.21	59.87	60.39
		Kensington 17W PT	62.78	63.62	64.11	64.93	65.48
		Kensington 34W PT	62.78	63.62	64.11	64.93	65.48
		Sylvania B2001 34W	57.95	58.77	59.21	59.87	60.39
		Sylvania StreetLED 18W	57.95	58.77	59.21	59.87	60.39
		Pecan NXT-24S 450 35W	61.11	61.94	62.41	63.17	63.71
		Alt Ledway 30 D350 39W	57.95	58.77	59.21	59.87	60.39
		Alt Ledway 20 D350 26W	57.95	58.77	59.21	59.87	60.39
		Pecan NXT-12S 525 20W	61.11	61.94	62.41	63.17	63.71
		Pecan NXT-24S 350 29W	61.11	61.94	62.41	63.17	63.71

Category	Service Description	Option	2020/21	2021/22	2022/23	2023/24	2024/25
		Sylvania StreetLED 17W - Regional	57.95	58.77	59.21	59.87	60.39
		Bourke Hill 22W LED	61.44	62.27	62.75	63.52	64.06
	TFI	Sylvania StreetLED 17W	74.83	75.75	76.33	77.09	77.71
		Sylvania StreetLED 25W	75.87	76.79	77.37	78.15	78.78
		Sylvania StreetLED 18W	78.86	79.81	80.41	81.21	81.86
		Advanced Edge40 D350P 46W	75.05	75.97	76.55	77.31	77.94
		Pecan SAT-48S 44W	75.05	75.97	76.55	77.31	77.94
		Kensington 17W PT	114.78	115.95	116.82	117.99	118.85
		Kensington 34W PT	114.78	115.95	116.82	117.99	118.85
		Sylvania B2001 34W	75.05	75.97	76.55	77.31	77.94
		Sylvania StreetLED 18W	75.05	75.97	76.55	77.31	77.94
		Pecan NXT-24S 450 35W	101.01	102.09	102.86	103.89	104.67
		Alt Ledway 30 D350 39W	75.05	75.97	76.55	77.31	77.94
		Alt Ledway 20 D350 26W	75.05	75.97	76.55	77.31	77.94
		Pecan NXT-12S 525 20W	101.01	102.09	102.86	103.89	104.67
		Pecan NXT-24S 350 29W	101.01	102.09	102.86	103.89	104.67
		Sylvania StreetLED 17W - Regional	77.38	78.32	78.91	79.69	80.33
		Bourke Hill 22W LED	103.73	104.83	105.62	106.68	107.47
	SAPN	Sylvania StreetLED 17W	92.53	93.57	94.27	95.15	95.88
		Sylvania StreetLED 25W	94.73	95.78	96.50	97.40	98.14
		Sylvania StreetLED 18W	101.10	102.19	102.96	103.91	104.69
		Advanced Edge40 D350P 46W	93.00	94.03	94.74	95.63	96.36
		Pecan SAT-48S 44W	93.00	94.03	94.74	95.63	96.36
		Kensington 17W PT	177.59	179.16	180.49	182.08	183.32
		Kensington 34W PT	177.59	179.16	180.49	182.08	183.32
		Sylvania B2001 34W	93.00	94.03	94.74	95.63	96.36
		Sylvania StreetLED 18W	93.00	94.03	94.74	95.63	96.36
		Pecan NXT-24S 450 35W	148.27	149.66	150.77	152.12	153.18
		Alt Ledway 30 D350 39W	93.00	94.03	94.74	95.63	96.36
		Alt Ledway 20 D350 26W	93.00	94.03	94.74	95.63	96.36
		Pecan NXT-12S 525 20W	148.27	149.66	150.77	152.12	153.18
		Pecan NXT-24S 350 29W	148.27	149.66	150.77	152.12	153.18
		Sylvania StreetLED 17W - Regional	96.72	97.78	98.51	99.42	100.18

Category	Service Description	Option	2020/21	2021/22	2022/23	2023/24	2024/25
		Bourke Hill 22W LED	154.06	155.49	156.64	158.04	159.14
V Category	CLER	Pecan SAT-96M 200W	18.14	18.27	18.41	18.74	18.86
		Aldridge LED 105W	21.47	21.61	21.79	22.23	22.37
		Aldridge LED 198W	21.47	21.61	21.79	22.23	22.37
		Alt Ledway 40 D700 88W	18.14	18.27	18.41	18.74	18.86
		Advanced Edge40 D525P 70W	18.14	18.27	18.41	18.74	18.86
		A1 Insights 150W	17.51	17.63	17.77	18.07	18.19
		Advanced Edge40 D700 88W	18.14	18.27	18.41	18.74	18.86
		Pecan SAT-48S 72W	18.14	18.27	18.41	18.74	18.86
		Pecan NXT-72M 117W	19.54	19.68	19.84	20.21	20.34
		Pecan NXT-72M 158W	19.54	19.68	19.84	20.21	20.34
		Aldridge ALS216 298W	21.47	21.61	21.79	22.23	22.37
		Pecan SAT-96M 178W	18.14	18.27	18.41	18.74	18.86
		Sylvania RoadLED 175W	18.49	18.62	18.77	19.11	19.23
		Pecan NXT-72M 350 78W	19.54	19.68	19.84	20.21	20.34
		Sylvania RoadLED 80W	17.51	17.63	17.77	18.07	18.19
		A1 Insights 150W - Regional	17.50	17.62	17.77	18.07	18.18
		Sylvania RoadLED 80W - Regional	18.52	18.65	18.80	19.13	19.26
		Sylvania RoadLED 60W	17.33	17.45	17.60	17.89	18.01
		Parkville 155W	21.26	21.41	21.58	22.01	22.15
		Parkville 80W	21.26	21.41	21.58	22.01	22.15
		Parkville 100W	21.26	21.41	21.58	22.01	22.15
	PLC	Pecan SAT-96M 200W	59.78	60.61	61.07	61.79	62.32
		Aldridge LED 105W	62.92	63.76	64.25	65.07	65.62
		Aldridge LED 198W	62.92	63.76	64.25	65.07	65.62
		Alt Ledway 40 D700 88W	59.78	60.61	61.07	61.79	62.32
		Advanced Edge40 D525P 70W	59.78	60.61	61.07	61.79	62.32
		A1 Insights 150W	59.19	60.01	60.47	61.16	61.69
		Advanced Edge40 D700 88W	59.78	60.61	61.07	61.79	62.32
		Pecan SAT-48S 72W	59.78	60.61	61.07	61.79	62.32
		Pecan NXT-72M 117W	61.11	61.94	62.41	63.17	63.71
		Pecan NXT-72M 158W	61.11	61.94	62.41	63.17	63.71
		Aldridge ALS216 298W	62.92	63.76	64.25	65.07	65.62
		Pecan SAT-96M 178W	59.78	60.61	61.07	61.79	62.32

Category	Service Description	Option	2020/21	2021/22	2022/23	2023/24	2024/25
		Sylvania RoadLED 175W	60.11	60.94	61.41	62.13	62.67
		Pecan NXT-72M 350 78W	61.11	61.94	62.41	63.17	63.71
		Sylvania RoadLED 80W	59.19	60.01	60.47	61.16	61.69
		A1 Insights 150W - Regional	59.18	60.00	60.46	61.16	61.68
		Sylvania RoadLED 80W - Regional	60.14	60.97	61.43	62.16	62.70
		Sylvania RoadLED 60W	59.02	59.84	60.30	60.99	61.52
		Parkville 155W	62.73	63.57	64.05	64.87	65.42
		Parkville 80W	62.73	63.57	64.05	64.87	65.42
		Parkville 100W	62.73	63.57	64.05	64.87	65.42
	TFI	Pecan SAT-96M 200W	93.56	94.60	95.31	96.25	96.99
		Aldridge LED 105W	119.35	120.56	121.45	122.66	123.55
		Aldridge LED 198W	119.35	120.56	121.45	122.66	123.55
		Alt Ledway 40 D700 88W	93.56	94.60	95.31	96.25	96.99
		Advanced Edge40 D525P 70W	93.56	94.60	95.31	96.25	96.99
		A1 Insights 150W	88.66	89.67	90.34	91.24	91.94
		Advanced Edge40 D700 88W	93.56	94.60	95.31	96.25	96.99
		Pecan SAT-48S 72W	93.56	94.60	95.31	96.25	96.99
		Pecan NXT-72M 117W	104.44	105.55	106.34	107.39	108.19
		Pecan NXT-72M 158W	104.44	105.55	106.34	107.39	108.19
		Aldridge ALS216 298W	119.35	120.56	121.45	122.66	123.55
		Pecan SAT-96M 178W	93.56	94.60	95.31	96.25	96.99
		Sylvania RoadLED 175W	96.28	97.34	98.06	99.04	99.79
		Pecan NXT-72M 350 78W	104.44	105.55	106.34	107.39	108.19
		Sylvania RoadLED 80W	88.66	89.67	90.34	91.24	91.94
		A1 Insights 150W - Regional	90.93	91.96	92.65	93.56	94.28
		Sylvania RoadLED 80W - Regional	98.82	99.90	100.65	101.64	102.40
		Sylvania RoadLED 60W	87.30	88.30	88.96	89.84	90.54
		Parkville 155W	117.77	118.97	119.85	121.04	121.93
		Parkville 80W	117.77	118.97	119.85	121.04	121.93
		Parkville 100W	117.77	118.97	119.85	121.04	121.93
	SAPN	Pecan SAT-96M 200W	130.59	131.87	132.85	134.04	135.00
		Aldridge LED 105W	185.52	187.14	188.53	190.18	191.47
		Aldridge LED 198W	185.52	187.14	188.53	190.18	191.47
		Alt Ledway 40 D700 88W	130.59	131.87	132.85	134.04	135.00

Category	Service Description	Option	2020/21	2021/22	2022/23	2023/24	2024/25
		Advanced Edge40 D525P 70W	130.59	131.87	132.85	134.04	135.00
		A1 Insights 150W	120.16	121.37	122.27	123.38	124.28
		Advanced Edge40 D700 88W	130.59	131.87	132.85	134.04	135.00
		Pecan SAT-48S 72W	130.59	131.87	132.85	134.04	135.00
		Pecan NXT-72M 117W	153.76	155.19	156.34	157.73	158.82
		Pecan NXT-72M 158W	153.76	155.19	156.34	157.73	158.82
		Aldridge ALS216 298W	185.52	187.14	188.53	190.18	191.47
		Pecan SAT-96M 178W	130.59	131.87	132.85	134.04	135.00
		Sylvania RoadLED 175W	136.38	137.70	138.72	139.96	140.95
		Pecan NXT-72M 350 78W	153.76	155.19	156.34	157.73	158.82
		Sylvania RoadLED 80W	120.16	121.37	122.27	123.38	124.28
		A1 Insights 150W - Regional	123.77	125.00	125.93	127.06	127.98
		Sylvania RoadLED 80W - Regional	140.57	141.91	142.96	144.23	145.25
		Sylvania RoadLED 60W	117.26	118.45	119.33	120.41	121.29
		Parkville 155W	182.15	183.76	185.12	186.74	188.01
		Parkville 80W	182.15	183.76	185.12	186.74	188.01
		Parkville 100W	182.15	183.76	185.12	186.74	188.01

Table 17.40: Proposed annual public lighting charges – HID lights ($June 2020)

Category	Service Description	Option	2020/21	2021/22	2022/23	2023/24	2024/25
	Energy Only	All lights	3.06	3.09	3.13	3.17	3.20
P Category	CLER	Compact Fluorescent-42	64.89	65.32	65.81	66.26	66.66
		Fluorescent 2x14	64.89	65.32	65.81	66.26	66.66
		Fluorescent 2x8	64.89	65.32	65.81	66.26	66.66
		Compact Fluorescent 32	66.13	66.56	67.06	67.52	67.93
		Compact Fluorescent 42 – Post Top	66.13	66.56	67.06	67.52	67.93
		Fluorescent 11x2	43.86	44.16	44.49	44.80	45.08
		Fluorescent 20	43.86	44.16	44.49	44.80	45.08
		Fluorescent 2x20	43.86	44.16	44.49	44.80	45.08
		Fluorescent 2x40	43.86	44.16	44.49	44.80	45.08
		Fluorescent 40	43.86	44.16	44.49	44.80	45.08
		Fluorescent 3x40	43.86	44.16	44.49	44.80	45.08
		Fluorescent 4x40	43.86	44.16	44.49	44.80	45.08
		Fluorescent 8x2	43.86	44.16	44.49	44.80	45.08
		Incandescent 100	43.86	44.16	44.49	44.80	45.08
		Mercury 50	39.03	39.29	39.59	39.87	40.11
		Mercury 70	39.03	39.29	39.59	39.87	40.11
		Mercury 80	39.03	39.29	39.59	39.87	40.11
		Mercury 50 – Post top	45.70	46.01	46.36	46.68	46.97
		Mercury 80 – Post top	45.70	46.01	46.36	46.68	46.97
		High pressure sodium 50	62.28	62.69	63.17	63.60	63.99
		Sodium 18 LP	28.23	28.42	28.65	28.85	29.03
		Sodium 26 LP	28.23	28.42	28.65	28.85	29.03
		Sodium 18 LP – Post top	28.23	28.42	28.65	28.85	29.03
		Metal Halide 100	46.41	46.72	47.07	47.40	47.69
		Metal Halide 125	46.41	46.72	47.07	47.40	47.69
		Metal Halide 150	46.41	46.72	47.07	47.40	47.69
		Metal Halide 250	46.41	46.72	47.07	47.40	47.69
		Metal Halide 50	46.41	46.72	47.07	47.40	47.69
		Metal Halide 70	46.41	46.72	47.07	47.40	47.69
		Metal Halide 100 – Post top	46.41	46.72	47.07	47.40	47.69
		Sodium 70 – Post top	46.41	46.72	47.07	47.40	47.69

Category	Service Description	Option	2020/21	2021/22	2022/23	2023/24	2024/25
		Sodium 70	46.41	46.72	47.07	47.40	47.69
		Sodium 50 – Post top	50.93	51.27	51.66	52.02	52.33
	PLC	Compact Fluorescent 32	112.12	113.27	114.10	116.89	117.73
		Compact Fluorescent 42 – Post Top	139.19	140.51	114.10	116.89	117.73
	TFI	Compact Fluorescent 32	139.19	140.51	141.55	144.51	145.51
		Compact Fluorescent 42 – Post Top	112.12	113.27	141.55	144.51	145.51
	SLUOS	Compact Fluorescent-42	95.87	96.92	97.65	99.41	100.16
		Fluorescent 2x14	95.87	96.92	97.65	99.41	100.16
		Fluorescent 2x8	95.87	96.92	97.65	99.41	100.16
		Compact Fluorescent 32	127.85	129.09	130.04	132.94	133.87
		Compact Fluorescent 42 – Post Top	127.85	129.09	130.04	132.94	133.87
		Fluorescent 11x2	99.34	100.41	101.16	102.78	103.55
		Fluorescent 20	99.34	100.41	101.16	102.78	103.55
		Fluorescent 2x20	99.34	100.41	101.16	102.78	103.55
		Fluorescent 2x40	99.34	100.41	101.16	102.78	103.55
		Fluorescent 40	99.34	100.41	101.16	102.78	103.55
		Fluorescent 3x40	99.34	100.41	101.16	102.78	103.55
		Fluorescent 4x40	99.34	100.41	101.16	102.78	103.55
		Fluorescent 8x2	99.34	100.41	101.16	102.78	103.55
		Incandescent 100	99.34	100.41	101.16	102.78	103.55
		Mercury 50	75.42	76.34	76.92	78.00	78.62
		Mercury 70	75.42	76.34	76.92	78.00	78.62
		Mercury 80	75.42	76.34	76.92	78.00	78.62
		Mercury 50 – Post top	71.27	72.17	72.72	73.65	74.25
		Mercury 80 – Post top	71.27	72.17	72.72	73.65	74.25
		High pressure sodium 50	90.58	91.60	92.28	93.63	94.35
		Sodium 18 LP	83.32	84.29	84.92	86.69	87.36
		Sodium 26 LP	83.32	84.29	84.92	86.69	87.36
		Sodium 18 LP – Post top	83.32	84.29	84.92	86.69	87.36
		Metal Halide 100	96.66	97.71	98.44	100.01	100.76
		Metal Halide 125	96.66	97.71	98.44	100.01	100.76
		Metal Halide 150	96.66	97.71	98.44	100.01	100.76
		Metal Halide 250	96.66	97.71	98.44	100.01	100.76
		Metal Halide 50	96.66	97.71	98.44	100.01	100.76

Category	Service Description	Option	2020/21	2021/22	2022/23	2023/24	2024/25
		Metal Halide 70	96.66	97.71	98.44	100.01	100.76
		Metal Halide 100 – Post top	96.66	97.71	98.44	100.01	100.76
		Sodium 70 – Post top	96.66	97.71	98.44	100.01	100.76
		Sodium 70	96.66	97.71	98.44	100.01	100.76
		Sodium 50 – Post top	89.75	90.76	91.44	92.79	93.50
V Category	CLER	Mercury 100	25.18	25.35	25.55	25.73	25.90
		Mercury 125	25.18	25.35	25.55	25.73	25.90
		Mercury 125x3	25.18	25.35	25.55	25.73	25.90
		Mercury 250	25.18	25.35	25.55	25.73	25.90
		Mercury 400	25.18	25.35	25.55	25.73	25.90
		Mercury 400x2	25.18	25.35	25.55	25.73	25.90
		Mercury 125 – Post top	25.18	25.35	25.55	25.73	25.90
		Sodium 100 – Post top	49.45	49.78	50.16	50.50	50.81
		Sodium 100	49.45	49.78	50.16	50.50	50.81
		Sodium 150 – Post top	42.08	42.36	42.69	42.99	43.25
		Sodium 150	42.08	42.36	42.69	42.99	43.25
		Sodium 250	48.33	48.65	49.02	49.36	49.66
		Sodium 400	48.33	48.65	49.02	49.36	49.66
		Low Pressure Sodium 135	58.28	58.66	59.11	59.51	59.87
		Low Pressure Sodium 55	58.28	58.66	59.11	59.51	59.87
		Low Pressure Sodium 90	58.28	58.66	59.11	59.51	59.87
		Incandescent Flood 1000	27.98	28.17	28.39	28.59	28.77
		Incandescent Flood 150	27.98	28.17	28.39	28.59	28.77
		Incandescent Flood 1500	27.98	28.17	28.39	28.59	28.77
		Incandescent Flood 500	27.98	28.17	28.39	28.59	28.77
		Incandescent Flood 750	27.98	28.17	28.39	28.59	28.77
		Mercury Flood 1000	27.98	28.17	28.39	28.59	28.77
		Mercury Flood 250	27.98	28.17	28.39	28.59	28.77
		Mercury Flood 400	27.98	28.17	28.39	28.59	28.77
		Mercury Flood 750	27.98	28.17	28.39	28.59	28.77
		Mercury Flood 80	27.98	28.17	28.39	28.59	28.77
		Sodium Flood 360	27.98	28.17	28.39	28.59	28.77
		Sodium Flood 400	27.98	28.17	28.39	28.59	28.77
	SLUOS	Mercury 100	73.06	73.97	74.53	75.94	76.54
		Mercury 125	73.06	73.97	74.53	75.94	76.54

Category	Service Description	Option	2020/21	2021/22	2022/23	2023/24	2024/25
		Mercury 125x3	73.06	73.97	74.53	75.94	76.54
		Mercury 250	73.06	73.97	74.53	75.94	76.54
		Mercury 400	73.06	73.97	74.53	75.94	76.54
		Mercury 400x2	73.06	73.97	74.53	75.94	76.54
		Mercury 125 – Post top	73.06	73.97	74.53	75.94	76.54
		Sodium 100 – Post top	74.26	75.18	75.74	77.19	77.81
		Sodium 100	74.26	75.18	75.74	77.19	77.81
		Sodium 150 – Post top	76.20	77.12	77.70	79.22	79.85
		Sodium 150	76.20	77.12	77.70	79.22	79.85
		Sodium 250	87.25	88.25	88.90	90.81	91.51
		Sodium 400	87.25	88.25	88.90	90.81	91.51
		Low Pressure Sodium 135	92.97	94.00	94.70	96.81	97.53
		Low Pressure Sodium 55	92.97	94.00	94.70	96.81	97.53
		Low Pressure Sodium 90	92.97	94.00	94.70	96.81	97.53
		Incandescent Flood 1000	62.13	62.97	63.45	64.47	65.02
		Incandescent Flood 150	62.13	62.97	63.45	64.47	65.02
		Incandescent Flood 1500	62.13	62.97	63.45	64.47	65.02
		Incandescent Flood 500	62.13	62.97	63.45	64.47	65.02
		Incandescent Flood 750	62.13	62.97	63.45	64.47	65.02
		Mercury Flood 1000	62.13	62.97	63.45	64.47	65.02
		Mercury Flood 250	62.13	62.97	63.45	64.47	65.02
		Mercury Flood 400	62.13	62.97	63.45	64.47	65.02
		Mercury Flood 750	62.13	62.97	63.45	64.47	65.02
		Mercury Flood 80	62.13	62.97	63.45	64.47	65.02
		Sodium Flood 360	62.13	62.97	63.45	64.47	65.02
		Sodium Flood 400	62.13	62.97	63.45	64.47	65.02

Glossary

Abbreviation	Definition or description
ACS	Alternative control services
AER	Australian Energy Regulator
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
Augmentation	Investment in new network assets to meet increased demand.
BD	Business actual demand
B2R	Small business two-rate
BSR	Small business single-rate
Capacity	The amount of electrical power that a part of the network is able to carry.
Capital Contributed Works	Works for which the customer(s) contribute towards the cost of supplying assets, typically because they are the sole users.
CBD	Central business district
COAG	Council of Australian Governments.
Contestability	Customer choice of electricity or related service supplier.
Controlled Load	The DNSP controls the hours in which the supply is made available.
Cost of Supply Model	Theoretical and algorithmic model used to calculate prices, which conform to the pricing goals.
Cross subsidy	Where the price to a tariff class falls outside the range between the avoidable incremental cost of supply and the cost of stand-alone supply, an economic cross subsidy from or to other customers is said to exist.
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CT	Current Transformer – used in metering high voltage customers
Demand	Electricity consumption at a point in time.
Demand Management	Attempt to modify customer behaviour so as to constrain customer demand at critical times.
DER	Distributed Energy Resources, such as solar
Distribution Network	The assets and service which links energy customers to the transmission network.

Abbreviation	Definition or description
Distributor, DNSP	Distribution Network Service Provider.
DNSP	Distribution Network Service Provider
DUoS	Distribution Use of System. The utilisation of the distribution network in the provision of electricity to consumers (a component of NUoS).
DAPR	Distribution Annual Planning Report.
ESCoSA	Essential Services Commission of South Australia, a South Australian Regulator of energy and other infrastructure.
ESOO	Electricity Statement of Opportunities – prepared by the Australian Energy Market Operator (AEMO)
EV	Electric vehicle
EWOSA	Energy and Water Industry Ombudsman of South Australia
FiT	Feed-in Tariff, paid to customers that have solar generators.
FRMP	Financially Responsible Market Participant
GSL	Guaranteed Service Level
GWh	Gigawatt hours (a thousand-megawatt hours or a million kilowatt hours)
HBD	Large business HV actual monthly demand
HV/High Voltage	Equipment or supplies at voltages of 7.6kV or 11kV. Tariff: large business annual agreed demand
HV400	Large business HV annual agreed demand <400 kVA
IBT, Inclining Block Tariff	A network tariff energy rate in which the rate increases above specific consumption thresholds.
JSA	Jurisdictional Scheme Amount, a component of the Network Use of System charge to fund Feed-in Tariff payments to customers that have solar generators.
kVA, MVA	Kilo-volt amps and Mega-volt amps, units of apparent total electrical power demand. Usually the peak demand is referenced. See also PF for the relationship between power demand quantities.
kVAr, MVAr	Kilo-volt amps (reactive) and Mega-volt amps (reactive) units of instantaneous reactive electrical power demand. Usually the

Abbreviation	Definition or description
	peak demand is referenced. See also PF for the relationship between power demand quantities.
kW, MW	Kilo-watts and Mega-watts, units of instantaneous real electrical power demand. Usually the peak demand is referenced. See also PF for the relationship between power demand quantities.
kWh, MWh	Kilo-watt hours and Mega-watt hours, units of electrical energy consumption.
LB2R	Large business two-rate
LBSR	Large business single-rate
LV/Low Voltage	Equipment or supply at a voltage of 230V single phase or 400V, three phase. Tariff: LV annual demand
LV 1000	Business tariffs - annual demand with more than 1000 kVA
LRMC	Long run marginal cost
Marginal Cost	The cost of providing a small increment of service. The Long Run Marginal Cost (LRMC) includes future investment, Short Run Marginal Cost (SRMC) considers only the costs involved without extra investment.
Market Participant	Businesses involved in the electricity industry are referred to as Market or Code Participants.
Supply Rate	The fixed daily cost component of a Network price.
NEL	National Electricity Law.
NEM	National Electricity Market.
NER	National Electricity Rules.
NUoS	Network Use of System. The utilisation of the total electricity network in the provision of electricity to consumers (NUoS = DUoS + TUoS + PV FiT).
NMI	National metering identifier
NWD	A non-work day, Saturday and Sunday.
OPCL	Off-peak Controlled Load (includes electric hot water systems)
Opex	Operating expenditure
POE	%POE refers to the forecasting scenario as a percentage Probability of Exceeding the forecast proposed
PV FiT	Solar Photo Voltaic Feed-in Tariff

Abbreviation	Definition or description
PVNSG	Solar PV – non-scheduled generator. A commercial solar installation designed to inject power into the network rather than for self-consumption
PF	Power Factor, a measure of the ratio of real power to total power of a load. The relationship between real, reactive and apparent power is as follows: Power Factor = Real Power (kW) / Apparent Power (kVA) Apparent Power (kVA) = $\sqrt{[\text{Real Power (kW)}^2 + \text{Reactive Power (kVAr)}^2]}$
Price Signal	Prices set to convey a desired behaviour because of the costs associated with supplying the service.
Price Structure	The components that make up a Price available to customers.
RCP	Regulatory Control Period (usually 5 years)
Retailer	A Full Retail Contestability market participant (business) supplying electricity to customers.
Rules	National Electricity Rules
SBD	Small business actual demand
SBDT	Small business actual demand transition
SCS	Standard control service
SLV	Small business agreed demand
Sub-transmission	Equipment or supplies at voltage levels of 33kV or 66 kV.
SWER	Single wire earth return
Tariff	Network price components and conditions of supply for a tariff class.
Tariff class	A class of customers for one or more direct control services who are subject to a particular tariff or particular tariffs with similar electricity demand and usage requirements.
ToU	Time-of-Use, a system of pricing where energy or demand charges are higher in periods of peak utilisation of the network.
Transmission Network	The assets and service that enable generators to transmit their electrical energy to population centres. Operating voltage of equipment is 275kV and 132kV with some at 66kV.
TSS	Tariff structure statement
TUoS	Transmission Use of System charges for the utilisation of the transmission network.

Abbreviation	Definition or description
Unmetered supply	A connection to the distribution system which is not equipped with a meter and has estimated consumption. Connections to public lights, phone boxes, traffic lights and the like are not normally metered.
VPP	Virtual power plant
WD	A work day, Monday through to Friday excluding public holidays.