SA Power Networks

Attachment 17

Tariff Structure Statement Part B - Explanatory Statement

2020-25 Revised Regulatory Proposal

10 December2019

This section outlines:

- the explanatory notes for proposed pricing structure;
- what we have heard from our customers and stakeholders; and
- our forecasts for customer growth, energy volumes, demand and new technologies that underpin our Tariff Structure Statement.

Company information

SA Power Networks is the registered Distribution Network Service Provider for South Australia.
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Disclaimer

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

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 Regulatory Control Period. 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
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 Part A
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17.1 Overview

The AER approved our January 2019 Tariff Structure Statement (**TSS**) in its October 2019 Draft Decision, but also made recommendations where we could strengthen the TSS. We discuss these, and how we have incorporated them in Section 17.5.2 of this document. This included preparing our TSS in two parts: Part A outlining our TSS in accordance with the NER, and Part B as an Explanatory Statement providing supporting explanations for the pricing structure by which SA Power Networks recovers the revenue allowed by the Australian Energy Regulator (**AER**).

Our TSS has been prepared 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. The proposed tariff structures in our revised TSS have remained the same as our 2020-25 Regulatory Proposal (**Original Proposal**). [1] Our forecast sales and demand assumptions remain based on AEMO's 2018 Electricity Statement of Opportunities (**2018 ESOO**), we have retained these assumptions for our 2020-25 Revised Regulatory Proposal (**Revised Proposal**), as AEMO's 2019 report provides no material change to its 2018 scenario (see 17.2.6 AEMO Analysis).

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 16% of residential customers and 18% of small business customers now have interval meters. We expect this to grow to 50% 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

[1] With the exception of small business time of use (**ToU**) and maximum demand tariff. Our Original Proposal had a maximum demand charge applying to small businesses using more than 70kVA of demand, this has now changed to 120kVA of demand. We have also amended the pricing balance between demand and usage following the LRMC price revision.

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.

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 can respond 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 regulatory proposal for the 2015-20 regulatory control period (**RCP**) 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 suggest 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.[2]

Meter types impact the tariff options that are available for small customers. Over time, small customers will move away from legacy Type 6 meters to interval Type 4 meters, which will increase the tariff options that are available to them. In this Explanatory Statement we refer to the different metering types that apply to the individual tariffs. The meter types are:

- Type 4 (interval meter, typically remotely read). Consumption is recorded for each half hour interval. 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 like an odometer in a car. It measures energy used to date. Type 6 meters can have different meter components which impact on tariffs used. For example:

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

  - 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).
- Type 7 (unmetered supplies). Special arrangements are used for the measurement of energy used by unmetered supplies such as streetlights.

Our new cost-reflective tariffs will apply to all existing customers with interval meters and as customers migrate to a new or replacement interval 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.

The changes proposed in our TSS

The changes proposed in our TSS for the 2020-25 RCP 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 residential inclining 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 residential ToU tariff for those with interval (Type 4 or Type 5) meters, with peak times identified in the morning and evening while also recognising the 'solar trough'. Our off-peak times are determined to be 1:00am to 6:00am 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 an interval (Type 4) meter where the monthly demand is measured as the highest average demand over a four-hour period from 5:00pm to 9:00pm for November through to March. The ToU usage rates are halved in the Prosumer tariff;
- introducing a small business ToU tariff for customers with interval meters where peak is defined as 5:00pm to 9:00pm on workdays and non-workdays from November to March. Shoulder price elements are also used to reflect typical business hours ie 7:00am to 9:00pm workdays (7:00am to 5:00pm November to March) at a higher price, with a low off-peak price at other times;
- introducing a small business TOU tariff with maximum demand charge that would apply to small businesses using more than 120kVA of demand. This tariff has ToU rates at 80%of the ToU tariff;
- 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. The CBD covers the 5000 postcode plus the River Torrens precinct properties supplied from the CBD;
- 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 Explanatory Statement demonstrates that workday and non-workday seasonal demands are not sufficiently different to drive tariff structures in all locations of South Australia, except for the CBD.

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 breached which can lead to 'high voltage' and other issues.

Although not a 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 workdays 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.

Our 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 RCP. The proposed tariff structure and 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.

The tariffs proposed for the 2020-25 RCP are included in our TSS Part A and presented in section 17.8 is further detail on how we developed these tariffs. 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 17B-1 below.

This TSS explanatory statement (Part B) should be read in conjunction with 'Tariff Structure Statement (Part A)', and 'Section 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 explanatory statement is outlined in Table 17B-1.

Figure 17B-1: SA Power Networks' tariff peak and off-peak times

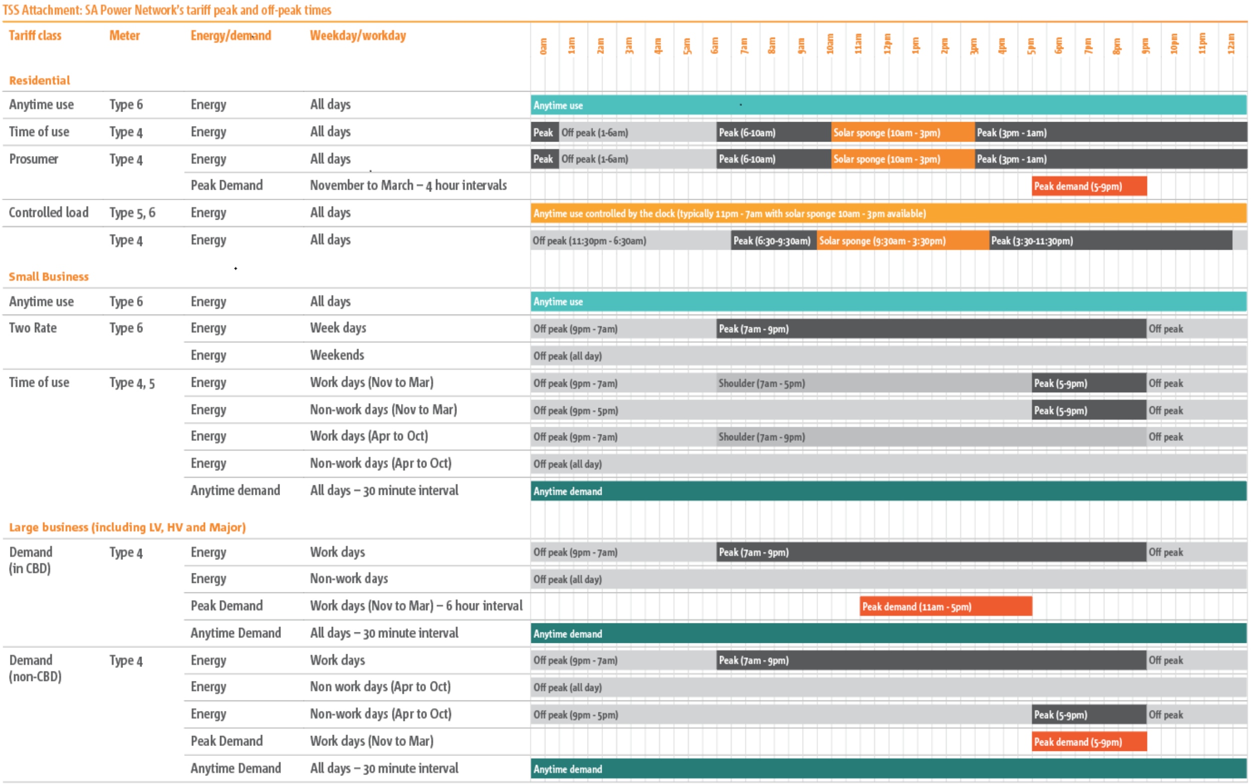


Table 17B-1: Tariff Structure Statement - document structure

Section	Title	Context
17.2	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**).
17.3	Customer impact principles	Describes the principles of tariff design that are important to our customers, and therefore drive the development of tariffs.
17.4	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.
17.5	AER Directions	Sets out the AER directions on tariff development which we need to apply.
17.6	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.
17.7	Our forecasts	Outlines the energy volume, customers, new technology and demand forecast assumptions used to develop the standard control indicative pricing for 2020-25.
17.8	Tariff design, development and assignment	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. How these have been developed within the customer impact principles, and the technology available to meter customer demand and energy consumption.
17.9	What do these tariffs mean for customers	A brief assessment of the changes to tariffs and what this means for customers.
17.10	Pricing methodology	A summary of the compliance with the customer principles and the National Electricity Rules.

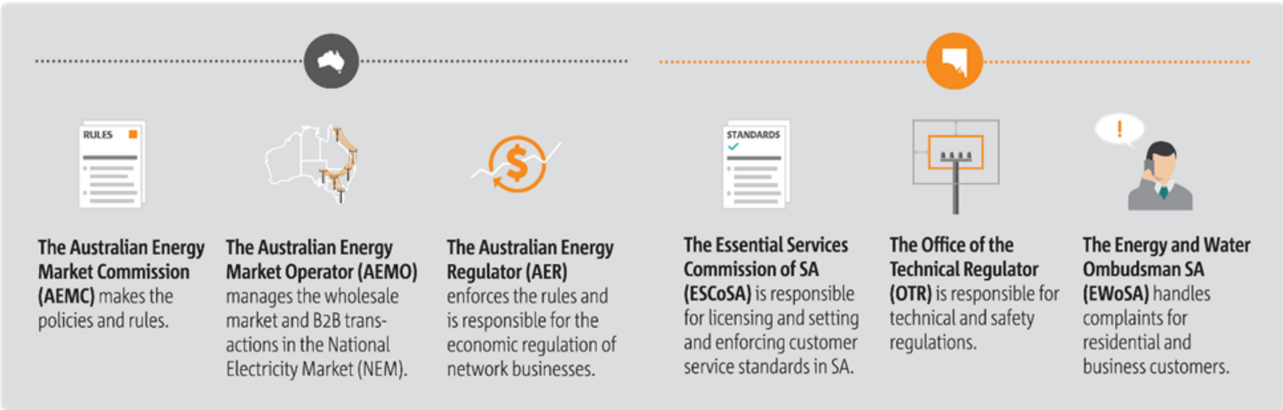
17.2 Characteristics of our network – what influences pricing and our forecasts

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

17.2.1 Who we are

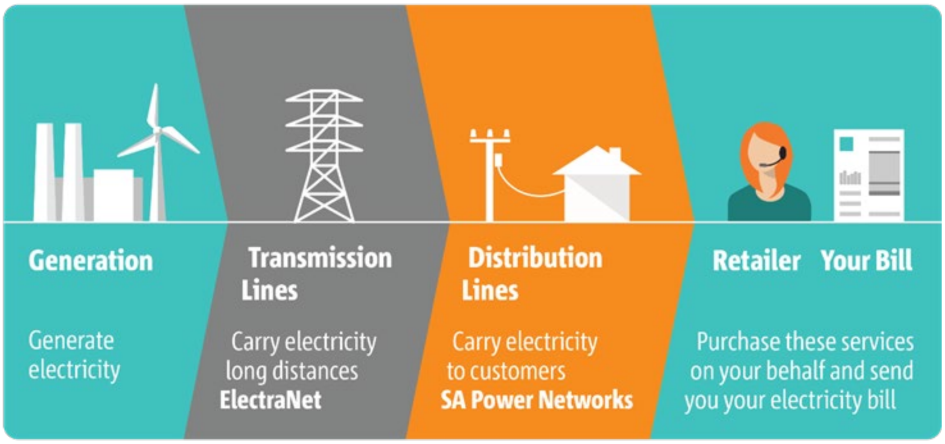
SA Power Networks is a Distribution Network Service Provider (**DNSP**) which operates within the National Electricity Market (**NEM**). We are governed by a number of agencies, rules and regulations at the National and State levels as shown in Figure 17B-2 below.

Figure 17B-2: SA Power Networks' governing agencies



The electricity supply chain consists of generation, transmission, distribution and retailers as shown in Figure 17B-3. In South Australia, ElectraNet provides the electricity transmission services and we provide the electricity distribution services to around 900,000 customers ranging from isolated farms in rural areas to industry precincts, regional and metropolitan residential homes, businesses and city centres.

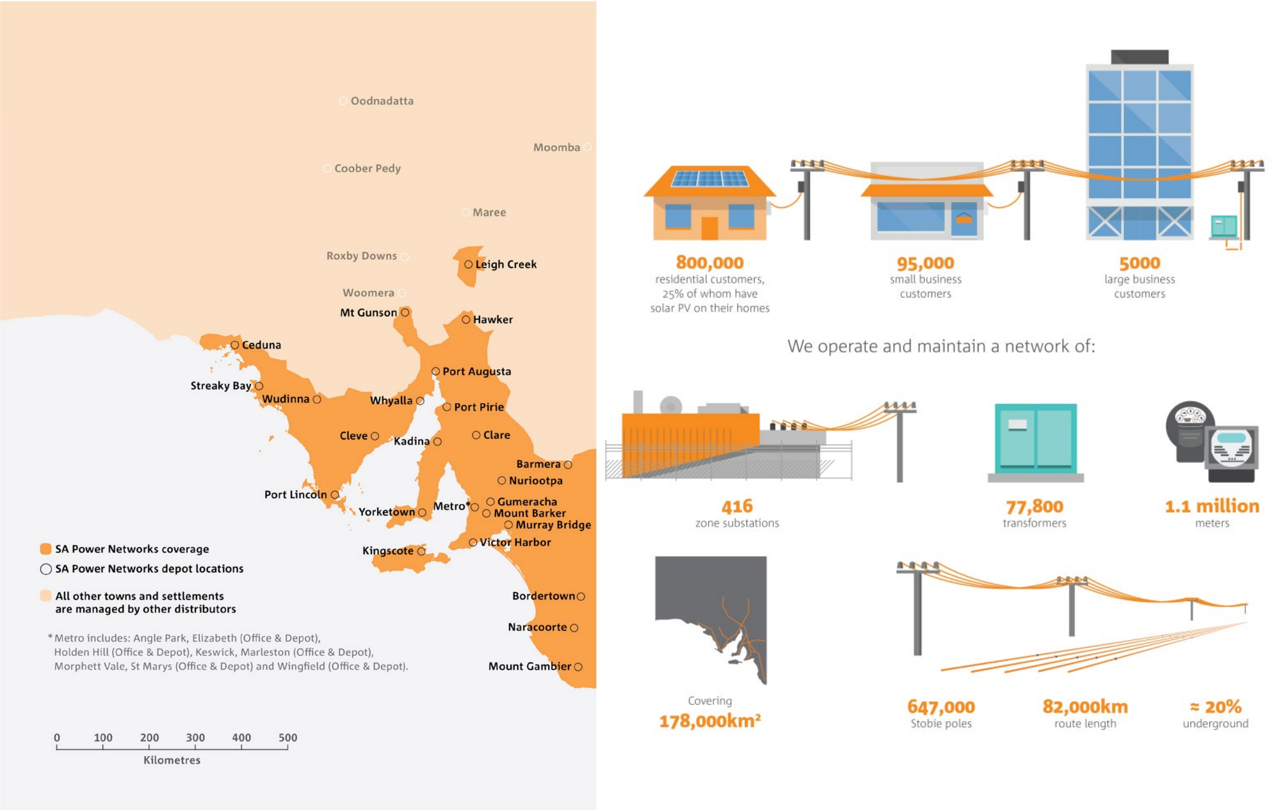
Figure 17B-3: Electricity supply chain



17.2.2 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 17B-4.

Figure 17B-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 11kV. The standard low voltage customer supply is 230V at 50Hz.

Except for 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.

17.2.3 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).

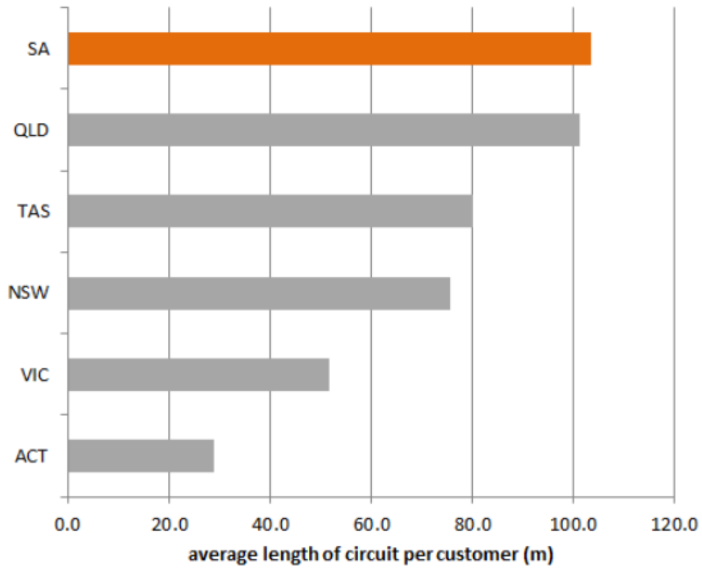
During these heatwave periods, summer daytime temperatures can exceed 40˚C for several days in a row and overnight minimums can remain above 30˚C for some of those days.

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.

17.2.4 Our customer density

As mentioned above, we supply electricity to around 900,000 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 17B-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 17B-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).[3] All of SA Power Networks' distribution tariffs are averaged.[4] 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[5] and so pricing reform in South Australia must be primarily based on peak demand or the ToU.

17.2.5 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 now 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.

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

[4] 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.

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

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.

17.2.6 AEMO Analysis

AEMO has developed an energy volume 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 analysis prepared by AEMO is used as support for our 2020-25 forecasts. Throughout this explanatory statement we will discuss where the AEMO forecasts have been used to assist the assumptions that we have applied to our own forecasts.

The data for energy efficiency, residential solar and business solar represent energy displaced from scheduled generation comes from the 2018 ESOO and has been used by SA Power Networks to determine energy volumes forecasts for 2019/20 and for the 2020-25 RCP. Since we submitted our original TSS for the 2020-25 RCP, AEMO has released its 2019 AEMO Electricity Statement of Opportunities (**2019 ESOO**). We have analysed the information provided in this report and found that the Central forecasts for the 2019 ESOO are very similar to the Moderate forecasts from the 2018 ESOO that underpinned our Original Proposal. As such, we have retained our forecast volumes from our Original Proposal for our Revised Proposal.

AEMO said in its November 2018 South Australian Electricity Report[6] that:

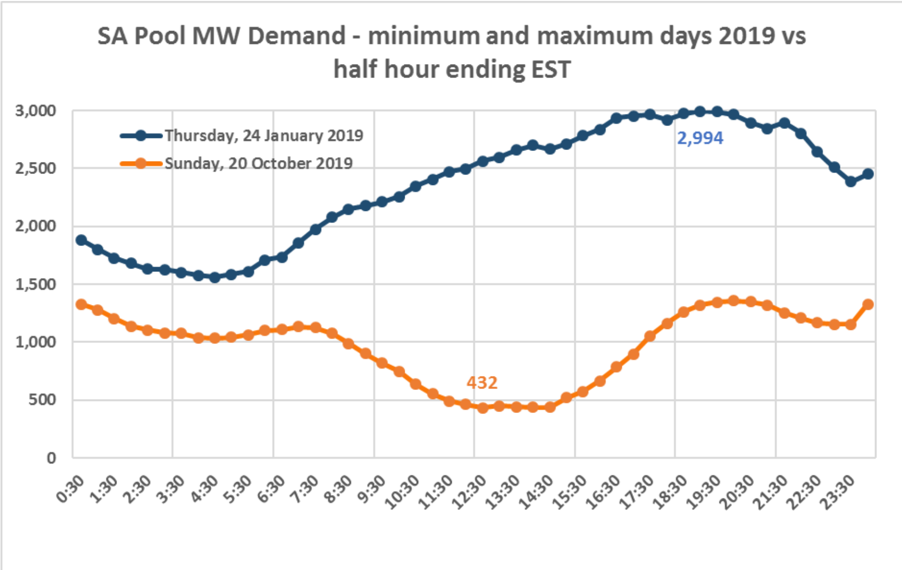
- "Rooftop solar contributed 8.2%[7] of the local generation mix in South Australia for 2017-18, with more than 30% of dwellings in South Australia now having rooftop solar systems installed (Analysis provided by the Australian PV Institute). AEMO estimated that rooftop solar contributed 1,162 GWh for the 2017-18 year."[8]
- "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." [9]
- "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." [10]

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.

[6] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/SA_Advisory/2018/2018-South-Australian-Electricity-Report.pdf
[7] *Ibid page 28.*
[8] *Ibid page 22.*
[9] *Ibid page 4.*
[10] *Ibid.*

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[11] 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 dispatched). On 2 December 2018 a lower minimum of 520MW was recorded at 13:30pm. Since December 2018, we have continued to see lower minimum demand on our system, the lowest to date being 20 October 2019 where 432MW was recorded at 12:30pm. Figure 17B-6 shows the minimum and maximum demand observed during 2019 for the SA Pool.

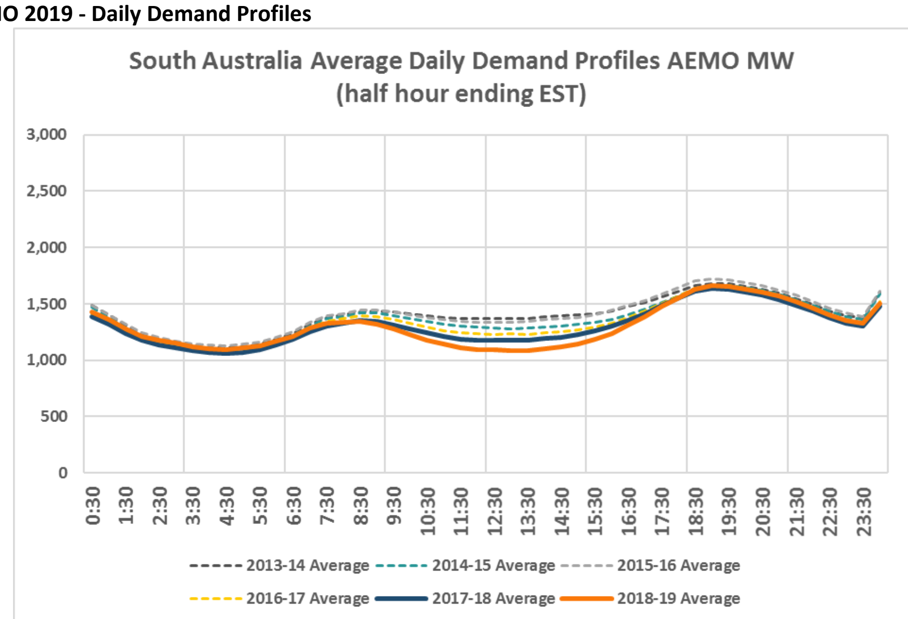
Figure 17B-6: SA Pool PW Demand min and max days 2019



Source: AEMO Forecasts and SA Power Networks analysis

AEMO makes the following observations over the previous six years in respect to the South Australian average daily demand profiles. The data in Figure 17B-7 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 2018/19 demand shows a reduction on the 2013/14 demand, influenced by energy efficiency and solar offsets.

Figure 17B-7: AEMO 2019 - Daily Demand Profiles

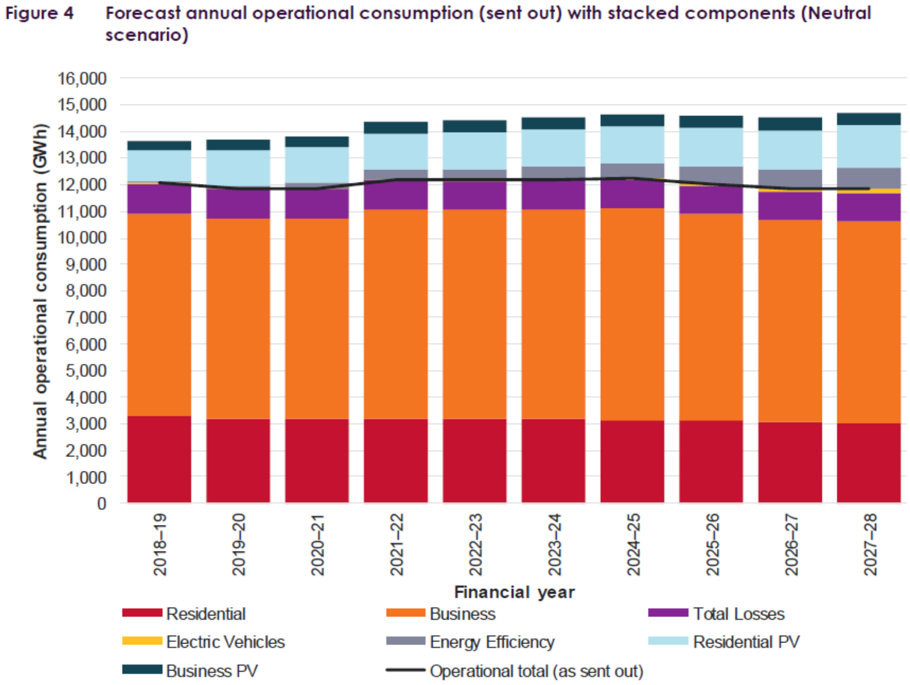


Source: AEMO Pool Data and SA Power Networks analysis

[11] Total net demand from the pool.

Figure 17B-8 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. Energy efficiency, residential PV and business PV represent energy displaced from scheduled generation.

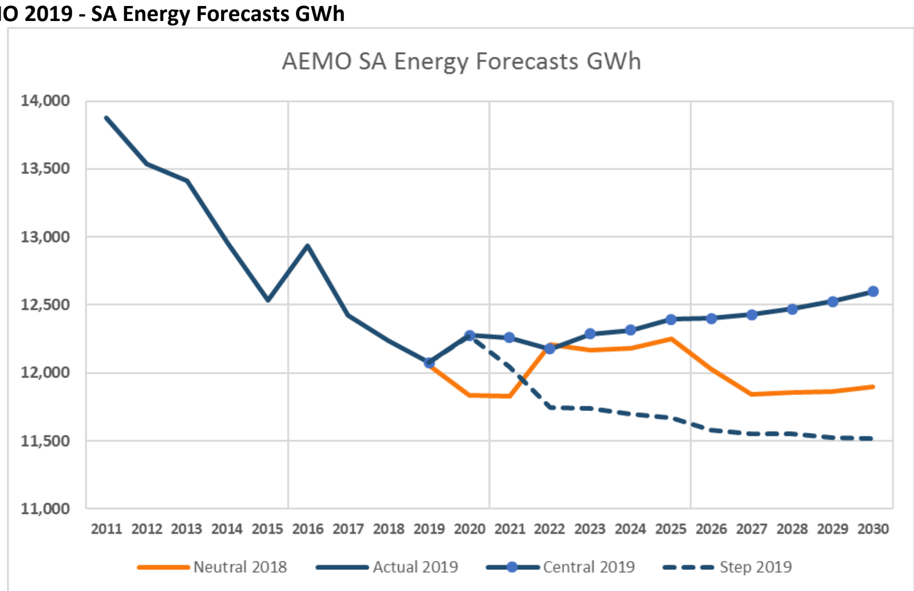
Figure 17B-8: AEMO 2018 - Forecast annual consumption (Figure 4 of AEMO 2018 Report)



Source: AEMO South Australian Electricity Report 2018, Page 20

In its 2019 ESOO, AEMO's base case forecast for the 2020-25 RCP remains essentially unchanged. AEMO's forecast now recognises a step change that could lower demand forecasts if PV and DER continue at a step change rate. We have maintained our existing forecasts for our energy forecasts that we proposed in our Original Proposal because, as shown in Figure 17B-9, there are only minimal changes between the 2018 neutral and 2019 central forecasts over the 2020-25 RCP. If an increase in PV and DER similar to the step change forecast occurs, we will recognise any sensitivities for this in our pricing. Refer to Figure 17B-14 below.

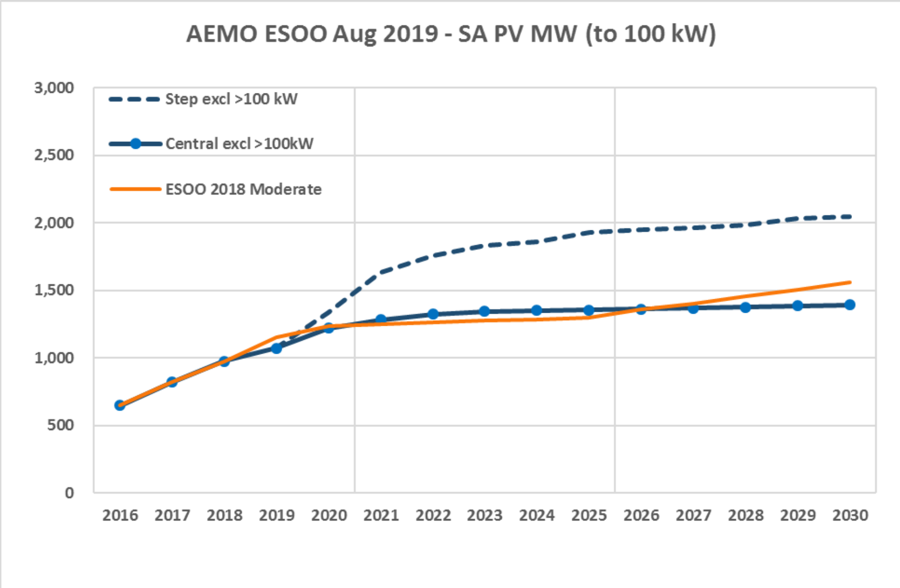
Figure 17B-9: AEMO 2019 - SA Energy Forecasts GWh



Source: AEMO Forecasts and SA Power Networks analysis

AEMO is forecasting a high take-up of solar through to 2020 (Figure 17B-10), 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. Note that the 2018 and 2019 forecasts are similar, but the step change has PV continuing to grow over the 2020-25 RCP at a similar rate to the 2015-20 RCP.

Figure 17B-10: AEMO 2019 - Forecast Rooftop solar - installed capacity under 100 kW



Source: AEMO Forecasts and SA Power Networks analysis

AEMO states in their 2018 Report on South Australia:[12]

> '*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)*'.

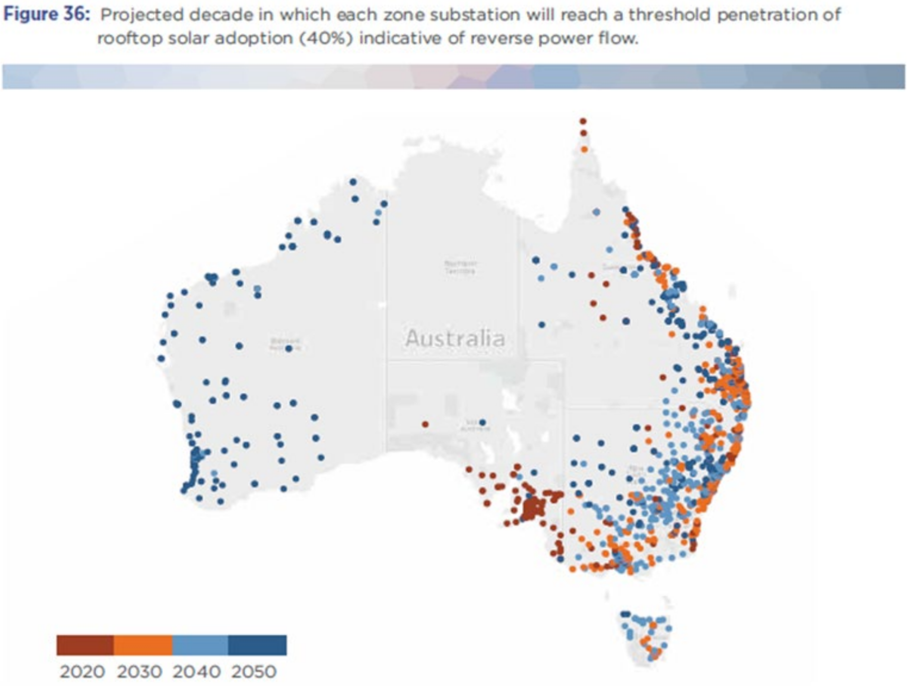
SA Power Networks has incorporated this solar production forecast into the 2020-25 energy volumes forecast, after adjusting for that proportion of solar production used in-house, that exported to the network, and that sent to batteries for subsequent in-house use. Energy volumes are reduced by in-house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

The continuing high growth in rooftop solar was forecast earlier by an independent study conducted by the Commonwealth Scientific and Industrial Research Organisation (**CSIRO**) and Energy Networks Australia[13] where they stated that the incidence of solar continues to grow. Analysis undertaken by them suggests that zone substations in South 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.

[12] AEMO, South Australian Electricity Report, November 2018, page 15.

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

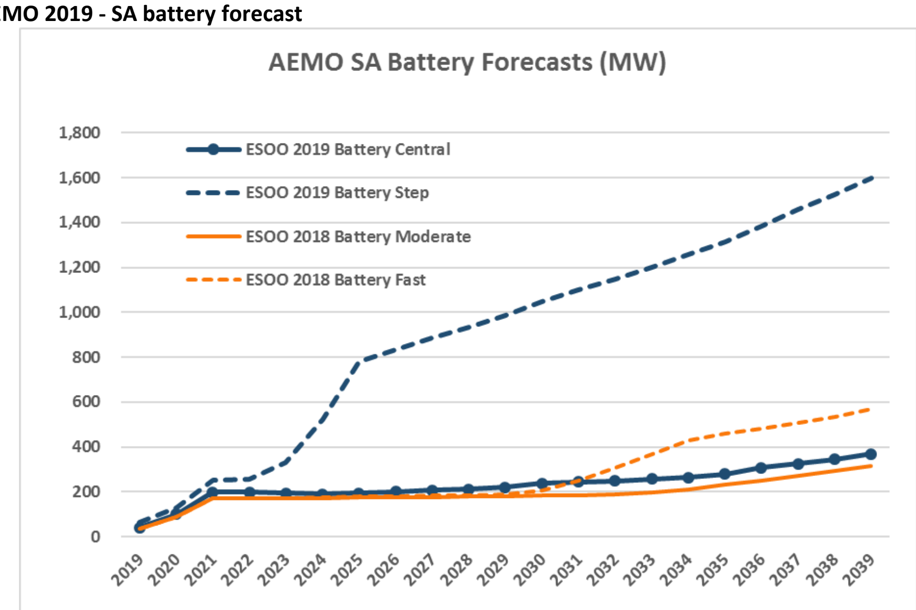
Figure 17B-11: Projected decade when zone substation reaches a reverse flow condition



Source: Electricity Network Transformation Roadmap: Final Report April 2017

AEMO's 2018 moderate and 2019 central forecasts are indicating a stable but flat battery uptake over the 2020-25 RCP after an initial burst associated with SA Government incentive programs. The step change forecast in the 2019 ESOO anticipates a second wave of batteries in the 2020-25 RCP, and a higher growth rate post 2025.

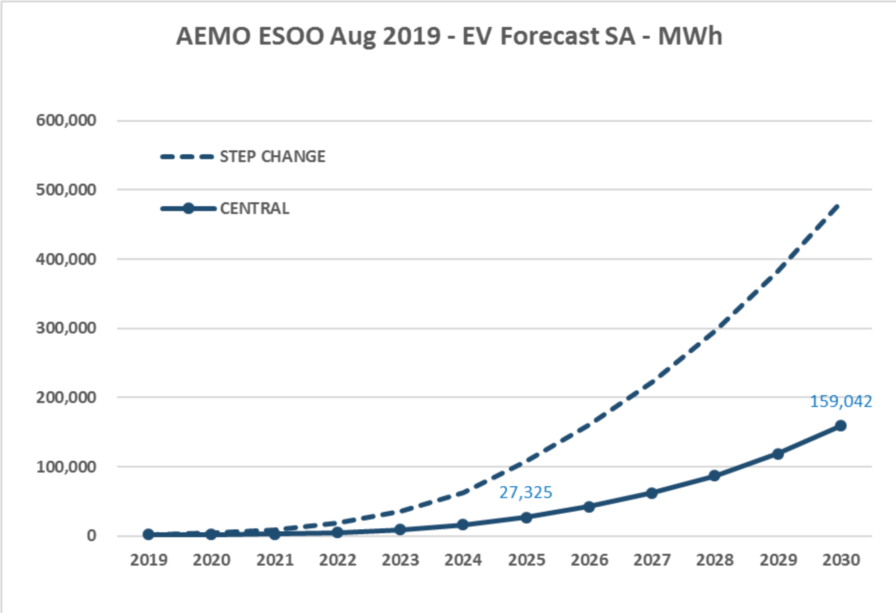
Figure 17B-12: AEMO 2019 - SA battery forecast



Source: AEMO Forecasts and SA Power Networks analysis

AEMO's forecast for EVs does not start to see an incline until part way through the 2020-25 RCP. Figure 17B-13 shows a forecast of 27GWh in 2025 for EVs, this is less than 0.3% of energy usage. The step change forecast for EVs is for about 100GWh or 1% of usage. EVs are not expected to have a material impact in the 2020-25 RCP, but early development of efficient recharging arrangements will assist in subsequent RCPs.

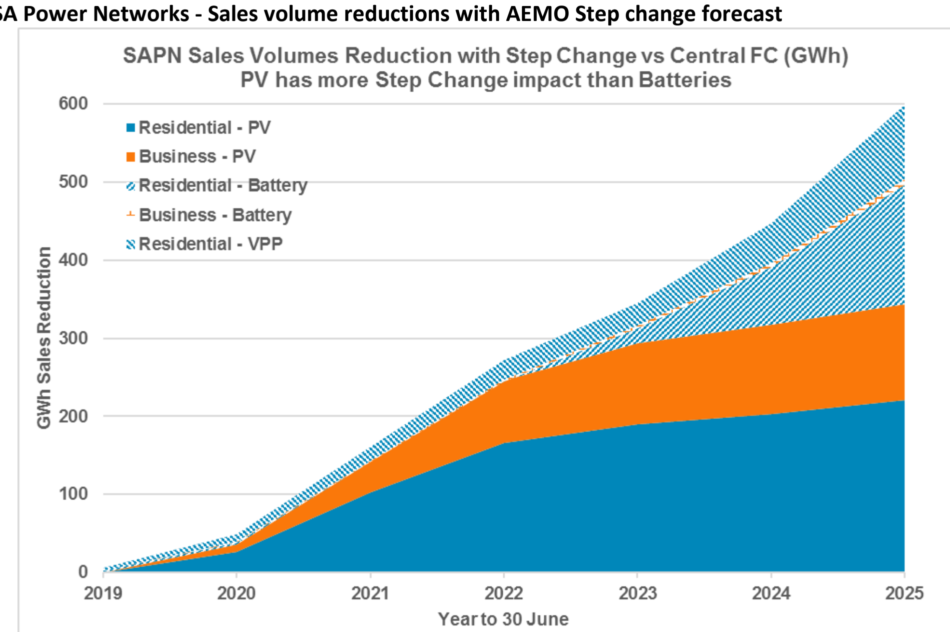
Figure 17B-13: AEMO 2019 - SA Electric Vehicle forecast



Source: AEMO Forecasts and SA Power Networks analysis

The potential impact of AEMO's forecast step change compared with its central forecast could see a fall in in energy sales by 600GWh or about 1% pa over the next six years to 2025. This decline is mostly through forecast step change in PV with a second wave in the latter years resulting from a predicted uptake of batteries. Figure 17B-14 shows the forecast GWh sales reduction by residential and business customers. Note that this is the incremental reduction from the step change versus the base case. Sales forecasts already include the impact of the base case solar and battery take-up. A 1% decline in usage volume is likely to produce about a 0.7% increase in prices. We have considered this sensitivity in selecting the smoothed revenue path which has an x-factor of 0.8%. If the step change occurs, the average price increase from lower sales volumes would be offset by the annual revenue reduction.

Figure 17B-14: SA Power Networks - Sales volume reductions with AEMO Step change forecast



Source: AEMO Forecasts and SA Power Networks analysis

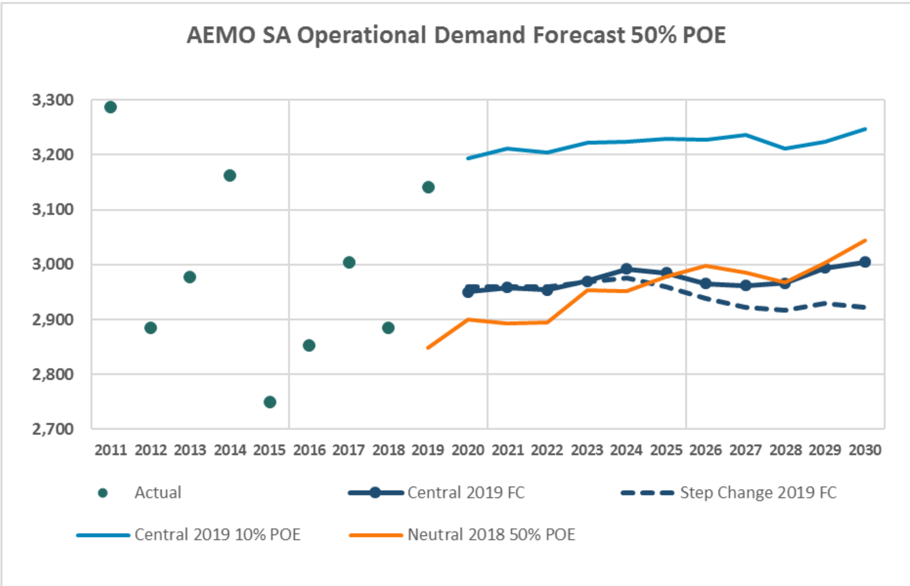
17.2.7 Coincident demand

AEMO has prepared a South Australian forecast for co-incident demand,[14] but this forecast does not include any detailed information on the separate contribution by customers connected to SA Power Networks' network and by those customers connected directly to ElectraNet's network. However, demand on SA Power Networks' network represents approximately 90% of total state demand (see Figure 17B-4), so the South Australian demand projection provides a sound guide for AEMO's expectations.

As depicted in Figure 17B-15, 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% probability of exceedance (**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).

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% POE forecasts. For the purposes of the forecast in the chart below, we made an adjustment to remove the large transmission related load growth in AEMO's 2022 forecast. As mentioned above, this load will not be 'experienced demand' on the SA Power Networks distribution system.

Figure 17B-15: AEMO 2019 – SA Operational Demand Forecast 50% POE



Source: AEMO Forecasts and SA Power Networks analysis

The load profile charts below 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-workdays and on extreme days.
- The diversity between the three profiles (solar export, residential and business).

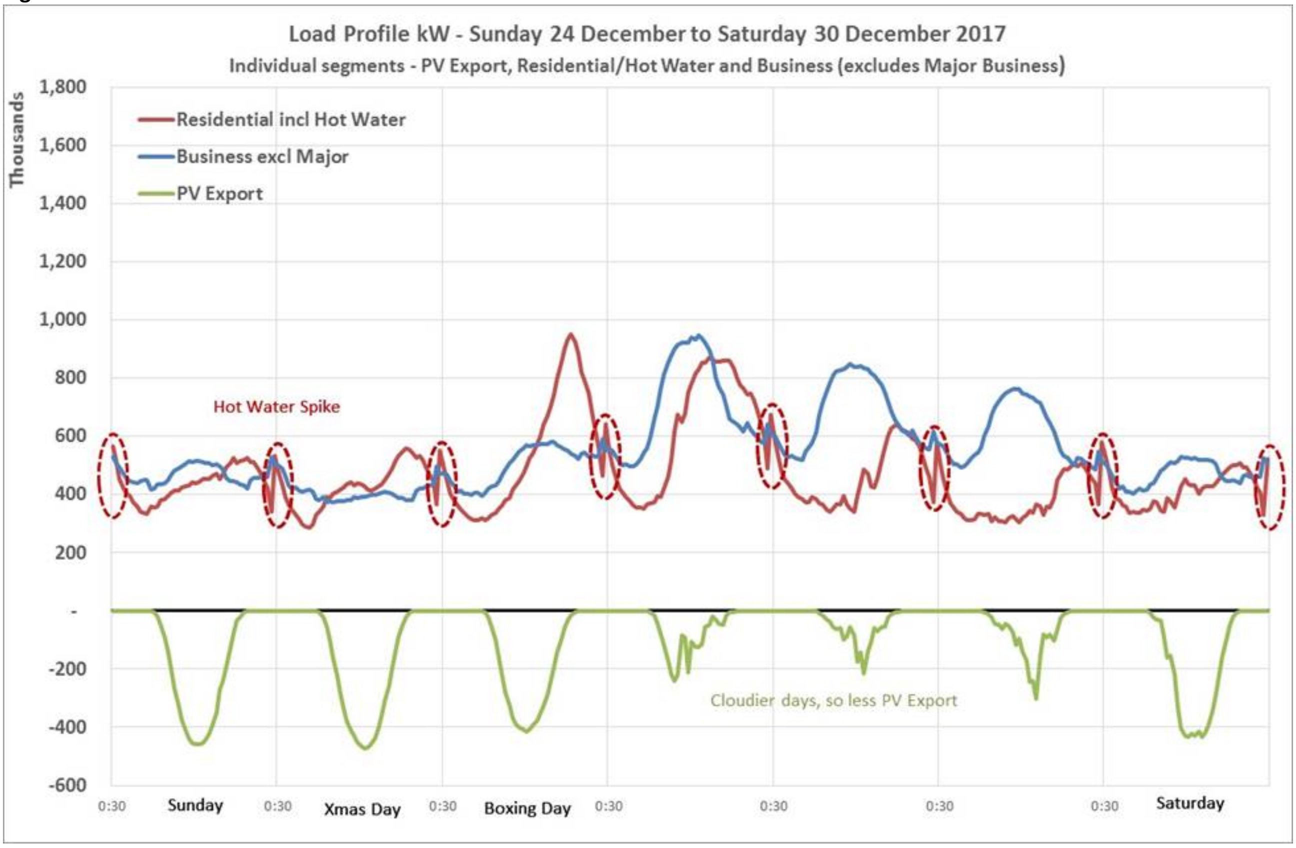
[14] AEMO, South Australian Electricity Report, November 2019.

Figure 17B-16 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 load (excluding major business) by the blue line. Figure 17B-17 shows the outcomes for a high demand period in mid-January 2018, a few weeks later.

If we combine the solar export and the Residential Load, the likely net Residential network profile can be seen. Figure 17B-18 and Figure 17B-19 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.

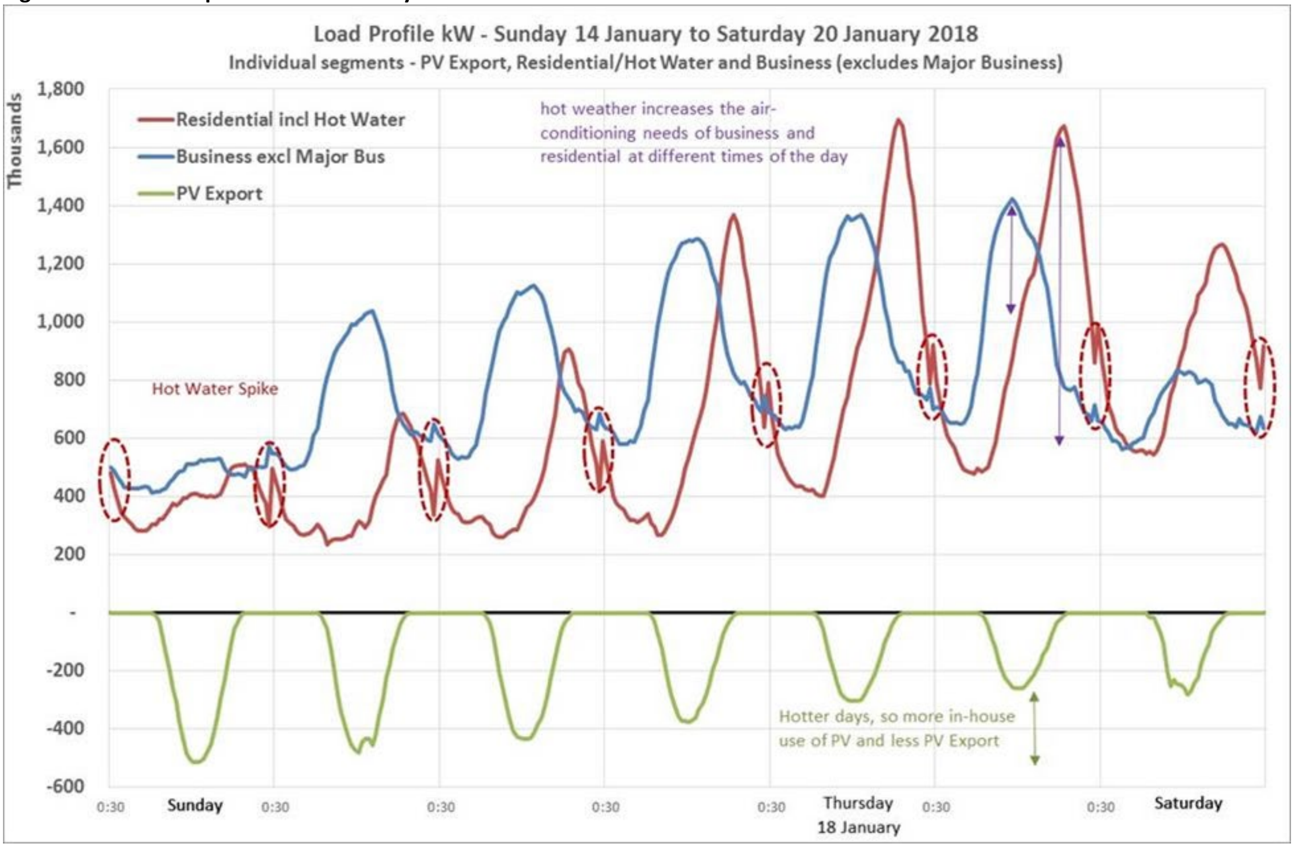
If we combine all these profiles, the likely distribution network profile (solar, Residential and Business) can be seen (the black line in the charts above). The minimum load occurs on Christmas Day, and the peak load in mid-January. The hot water spike near midnight can also be seen. The contribution 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 the 2020-25 RCP.

Figure 17B-16: Load Profile - Christmas week 2017



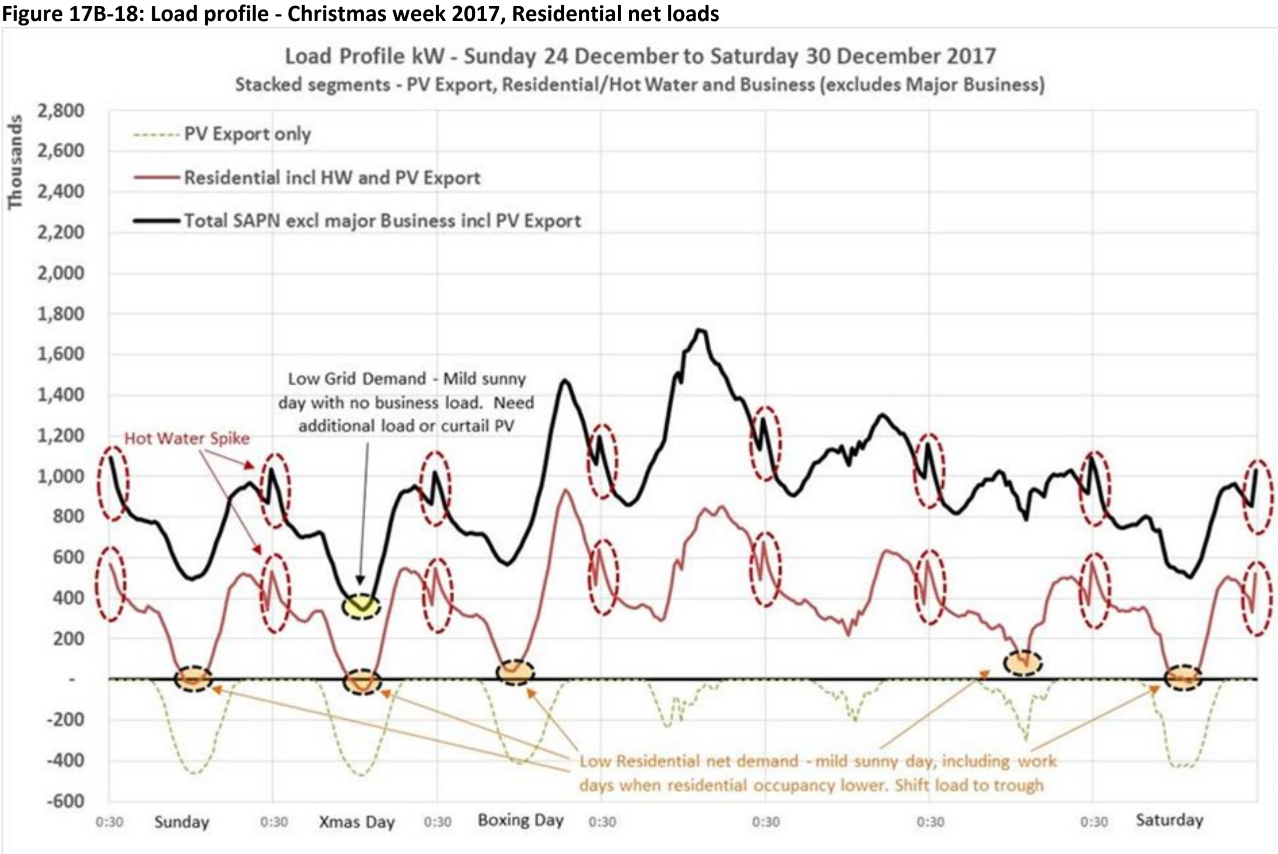
Source: SA Power Networks analysis

Figure 17B-17: Load profile - Mid-January 2018 week



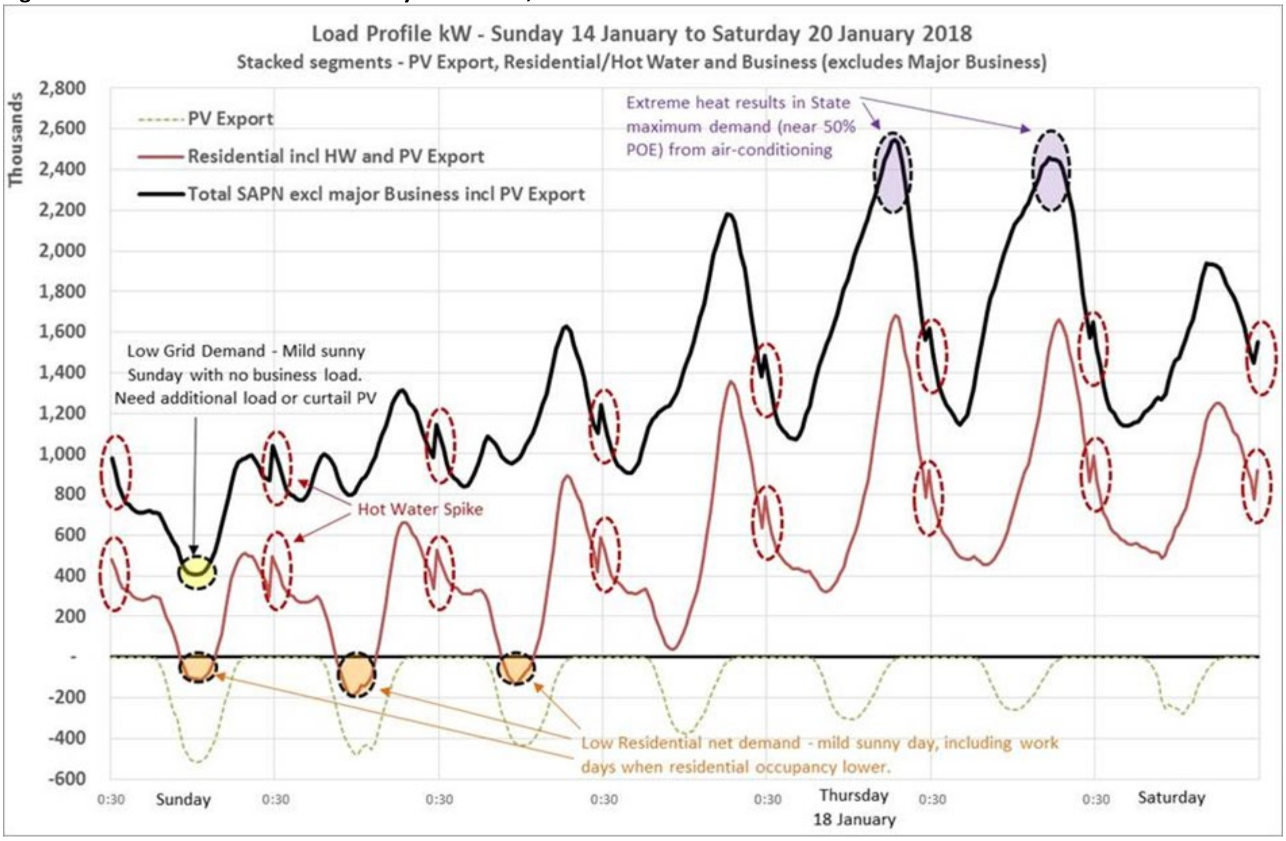
Source: SA Power Networks analysis

Figure 17B-18: Load profile - Christmas week 2017, Residential net loads



Source: SA Power Networks analysis

Figure 17B-19: Load Profile - Mid-January 2018 week, Residential net loads

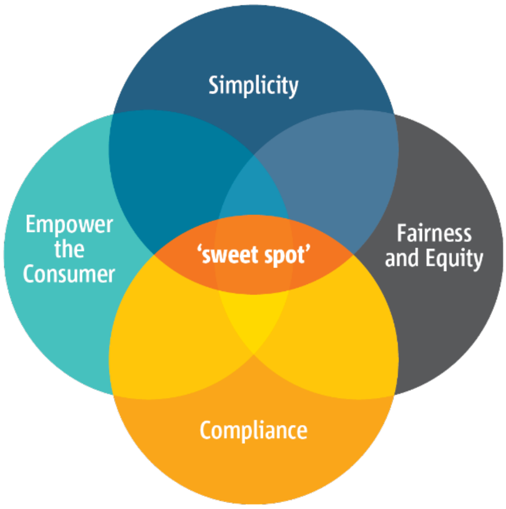


Source: SA Power Networks analysis

17.3 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 our TSS.

17.4 Customer engagement

Our customer engagement process is discussed in more detail in the *Customer and stakeholder engagement report* submitted with our Original Proposal. 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
- Australian Energy Council
- Retailers
  - Alinta Energy
  - AGL
  - Energy Australia
  - Lumo Energy
  - Origin Energy
  - PowerClub
  - Simply Energy

This engagement has occurred via reference group discussions, bilateral meetings, and a dedicated tariff deep dive workshop[15] (see Figure 17B-20), which brought together the diverse views of different stakeholder cohorts (see Table 17B-2).

Figure 17B-20: Tariff Structure Statement engagement

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

Table 17B-2: 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
"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

[15] *Supporting Document 0.10 - AnnShawRungie Tariffs Deep Dive Workshop Report, Original Proposal*

What we heard	Our response in this TSS
	• 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: - Riverland tariff trial retained for 2019/20 - A range of measures to address hot water being considered - 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.

Revised Proposal customer and stakeholder engagement

Since the submission of our Original Proposal in January 2019 we have continued to work with customers and retailers to ensure a smooth transition to the new tariffs and consider the impacts on different customer groups (see Figure 17B-21).

We have established a Residential and Business Tariff Working Group to work collaboratively to implement the new tariffs from 1 July 2020. The feedback from our customer engagement has identified the following points for further consideration during our TSS implementation process:

- incorporate the Default Market Offer implications of small customer tariffs (residential and business) explicitly into the Revised Proposal;

- develop communication strategies for 1 July 2020 reassignment of customers to TSS tariff proposals, including implications for that customer/retailer (for implementation in the second half of 2020);
- further work is to be done on identifying and engaging with customers who are most severely impacted; and
- maintain ongoing engagement with retailers, including a commitment to providing retailers with draft pricing schedules and system configurations.

Figure 17B-21: TSS Revised Proposal engagement

We will continue to engage with retailers as well as our customers and stakeholders on our tariff trials and tariff development, including opportunities for collaboration and community education to ensure the best outcomes for all South Australian customers.

17.5 AER Directions

17.5.1 2017-20 TSS AER Decision

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. It 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 17.4 and the Customer and stakeholder engagement report of our Original Proposal;
- the effect of emerging technologies and how we have responded is outlined in 17.6; and

- our response to balancing simplicity and affordability with cost reflectivity is set out in Section 17.10 and our TSS Part A.

17.5.2 2020-25 TSS AER Draft Decision

The AER's draft decision on our Original Proposal in October 2019 was to accept our TSS for the 2020-25 RCP, considering that it complies with the distribution pricing principles and contributes to the achievement of the network pricing objective.[16] While the AER accepted our 2020-25 TSS was compliant with the Rules, we were asked to consider areas that may further strengthen our proposal. These areas and where they have been covered within our TSS are as follows:

- Consider a targeted two-document TSS, with the first document limited to the content that will bind us over the RCP and the second providing explanations for the reasons behind adopting these positions.
  We have created two documents for our revised 2020-25 TSS, these are TSS Part A, and this TSS Part B (which forms an explanatory statement to Part A).
- LRMC methodology could be improved through some modifications and clarifications. This has been addressed in our pricing methodology sections in both our TSS Part A and in section 17.10 of this Part B.
  We have also updated our LRMC workings (Supporting Document 17.2, Revised Proposal) to address the AER's comments regarding linking LRMC estimates to forecast repex and augex.
- It would be helpful for consumers to have greater clarity on how unforeseen changes may be addressed. For example, should demand fall below forecast levels, how we will address these changes in revenue recovery through our annual pricing proposals.
  We have outlined our approach to unforeseen changes in TSS Part A.
- Distributors should set out in their TSS, how individually calculated tariffs for high voltage and sub transmission customers will be calculated and the criteria applied to customers to be able to access these tariffs.
  We have included our approach to individually calculated tariffs in Part A of our TSS.

17.6 The key challenges we are trying to address

17.6.1 Changing impacts on our customer – evolution of the 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. The way customers are using our distribution network is changing. In the past decade we have seen the influx of several 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.

To determine the outlook for demand and energy over the 2020-25 RCP we must have regard to the changes in customer take-up of the technologies identified, their demands on the system and the energy consumed. This directly influences how we develop charges for the recovery of the allowed revenues set out in our proposal.

Solar

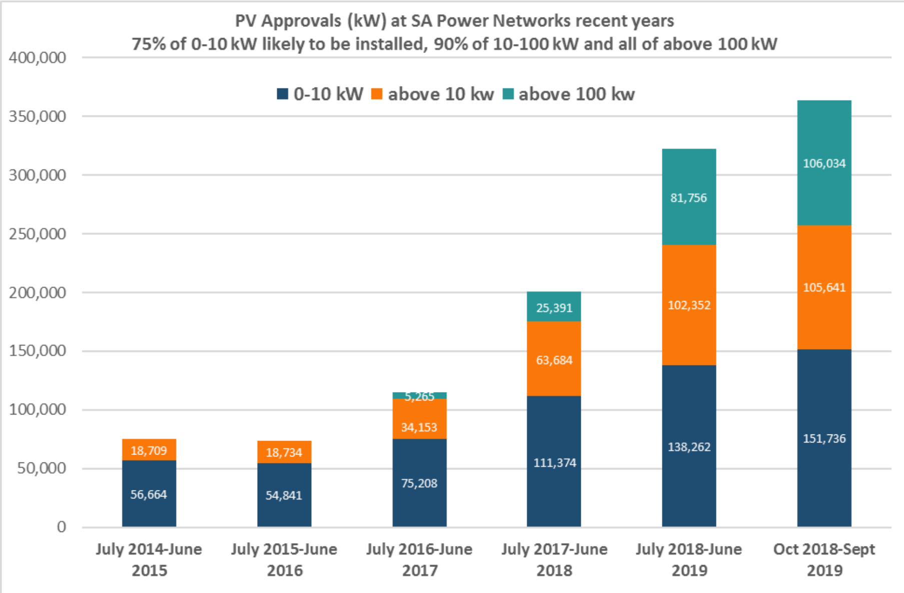
The impact of solar is changing. In the past, this technology was installed on the roof of the residential customer and we have seen this grow to a position where now more than 30% of our residential customers

[16] AER, *Draft Decision SA Power Networks Distribution Determination 2020 to 2025 - Attachment 18 Tariff Structure statement*, October 2019, page 18-9.

have solar installed on their roof. This was influenced initially by Government subsidies that supported solar installation and 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 still 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**). Figure 17B-22 shows the historical approvals of PV by kW for the connection of new solar installations at SA Power Networks. Whilst not all approvals proceed to connection, the significant majority do (see chart below).

Figure 17B-22: Historical PV Approvals (kW) at SA Power Networks



Source: SA Power Networks analysis

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.[17] 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.

Figure 17B-12: AEMO 2019 - SA battery forecast, demonstrates the forecast take up of battery storage by customers as prepared by 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.

There is no difference between the '2018 Moderate' and '2019 Central' forecasts as prepared by AEMO. For consistency, SA Power Networks has used the '2018 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.

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[17] 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*

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[18] (a policy of the former South Australian Labor Government).

Electric Vehicles

The take-up of EVs in South Australia is not expected to have any significant impact during the 2020-25 RCP. Figure 17B-13 shows the AEMO 2019 ESOO forecast for electric vehicles in South Australia.

The cost of the products and the operational range of the current products appear to make this technology unattractive to most 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.

17.6.2 The residential daily profile has moved our peak

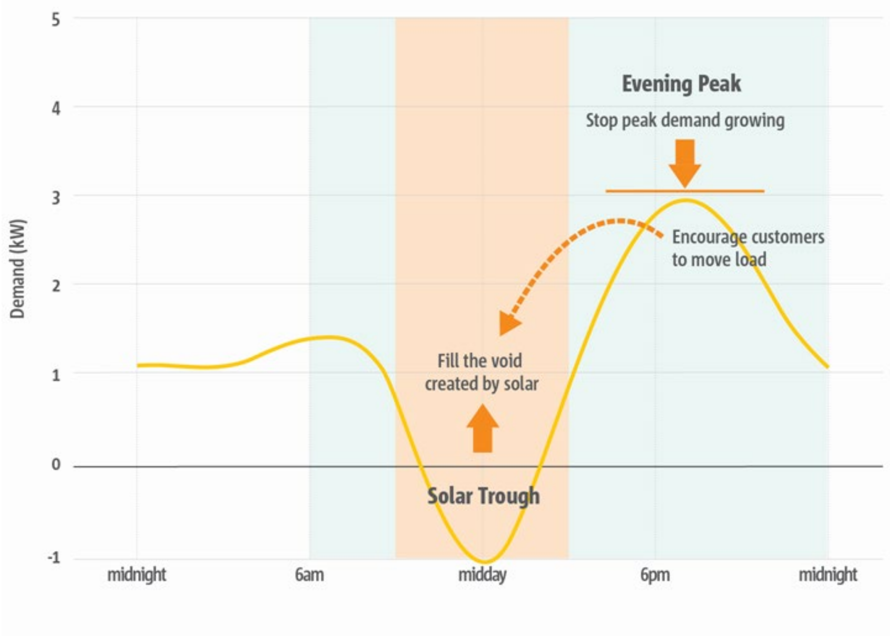
Until recently, ever-increasing customer demand required us to build more network capacity, primarily to meet increased residential air-conditioning loads on relatively few very hot summer days. The highest demand for electricity from our network was recorded back in 2009. Since then, overall net system 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. Analysis of our peak demand includes timing and locational issues which shows how the peak differs between parts of the network and times of the day. The 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 17B-23 shows the outcomes SA Power Networks is trying to achieve via our 'drop the peak' and 'fill the trough' strategies. A network is different to a generator and a retailer, but these desired network outcomes could also apply to generation and retail. 'Drop the peak' reduces the need for peaking generation and price caps. 'Fill the trough' enables better utilisation of mid-range plant and of price swaps. Any reduction in the slope of demand increasing/decreasing reduces the need for fast start/stop generation. If these network pricing strategies are adopted, there could be consequential impacts from lower future generation and retailing costs.

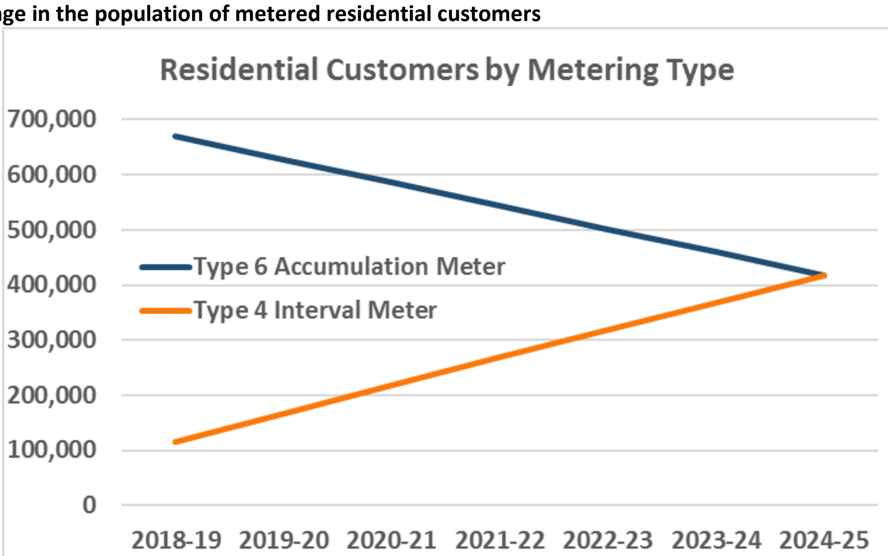
[18] *The South Australian Government announced a Virtual Power Plant (VPP) program for public housing tenants in 2017-18. The VPP program will provide Housing Trust tenants with an option to apply for solar panels and batteries to be installed on their Housing Trust property. Around 1,100 tenants will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

Figure 17B-23: 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 16% of residential customers and 18% of small business customers currently connected to our network are supplied through interval meters, but we expect this to move to 50% by 2025 (see below Figure 17B-24). All new and replacement meters must now be Type 4 meters under the metering contestability rule changes that applied from December 2017.

Figure 17B-24: Change in the population of metered residential customers



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 EVs 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, EVs 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 2020–25 RCP.

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.

17.6.3 Peak Demand

In this section, 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 customer impact principles identified in Section 17.3 and we will test any conclusions against these principles in the discussion that follows.

17.6.3.1 Matters Influencing the peak demand window in South Australia

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 workdays 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.

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 Australia 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[19]. 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 Attachment.
Response: We need to consider where summer demand is growing on our network. 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.

17.6.3.2 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), workdays 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:

1. What is the peak demand window today? What will it be in 2025 when the next increment of solar has been installed?
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?
3. What time of year is the peak window open? (Is it November through March).
4. Does the window/level of demand vary in these ‘regions’ according to work-day and non-workday? Does it make more economic sense to treat such days as ‘peak’ or as ‘off-peak’?
5. How should we incorporate these ‘windows’ into tariffs? Options include:

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

a. Agreed Demand tariffs.
b. Actual Demand tariffs.
c. Residential Prosumer Demand tariffs.
d. ToU Energy tariffs – Small business.
e. ToU Energy tariffs – Residential.

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.

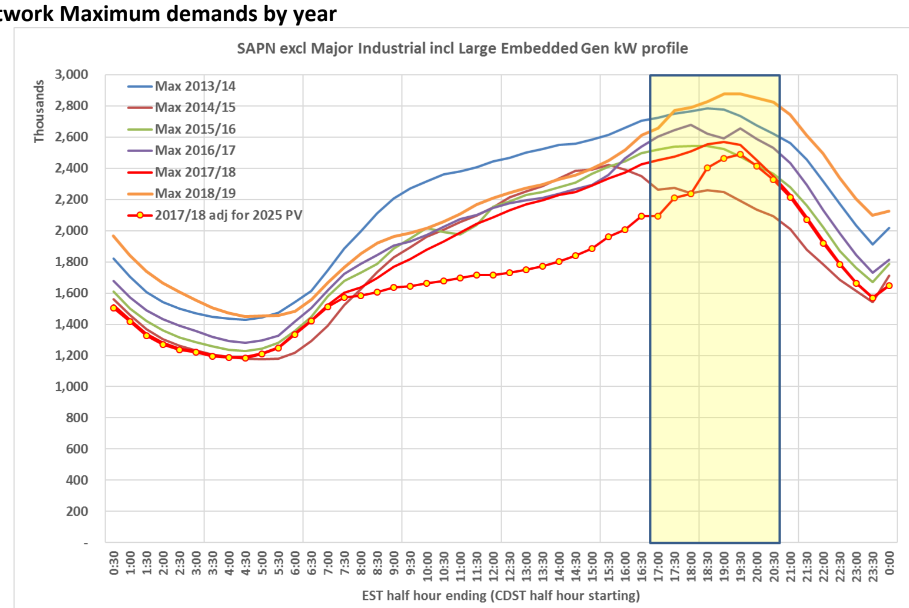
However, with the take up of solar, our network peak has experienced two changes:

- *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.[20]

Figure 17B-25 below plots the peak demand and its change over time and identifies at what part of the day this peak window occurs. It 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 the summer in 2013/14 was a particularly hot summer, and 2015/16, and 2017/18 also suffered heat wave conditions, which is consistent with the observed demands.

Figure 17B-25: Network Maximum demands by year



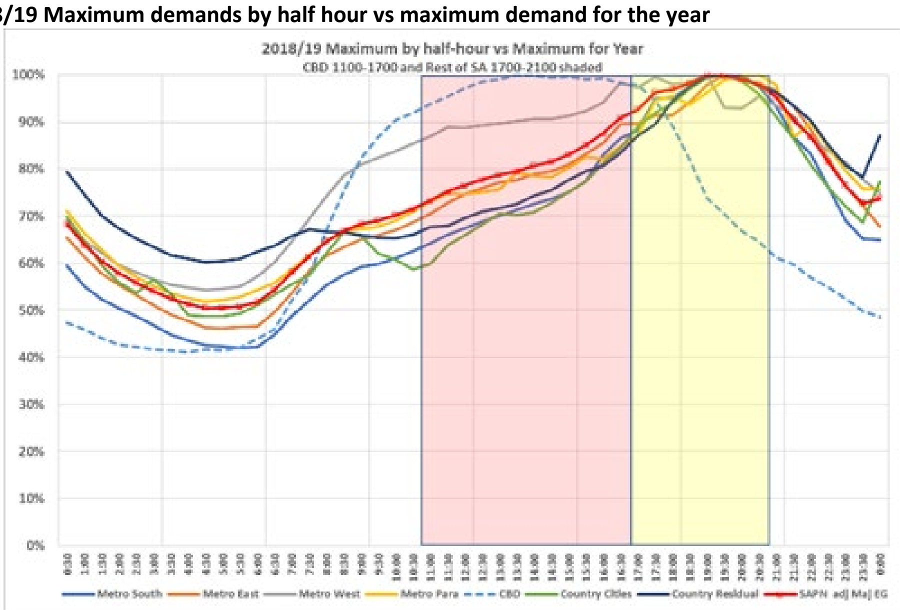
Source: SA Power Networks analysis

[20] *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)*

In Figure 17B-26, 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 2018/19 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.

These figures demonstrate that 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.

Figure 17B-26:2018/19 Maximum demands by half hour vs maximum demand for the year



Source: SA Power Networks analysis

Locational zones – 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 17B-27) sets out the size of the relevant sub-regions during an extreme demand day in the period 2013/14 through to 2018/19. Figure 17B-28 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 17B-27: Extreme day demands by sub-region (historical)

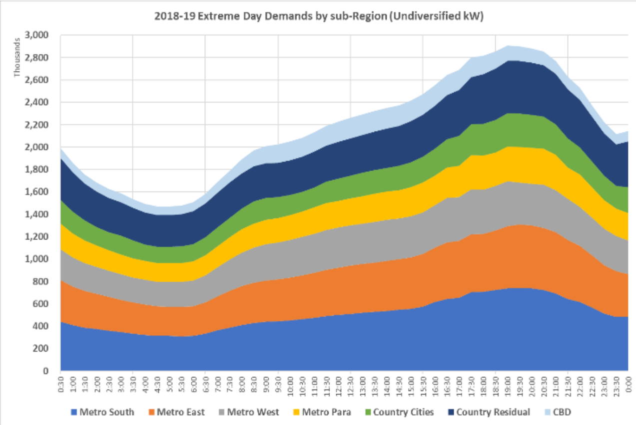
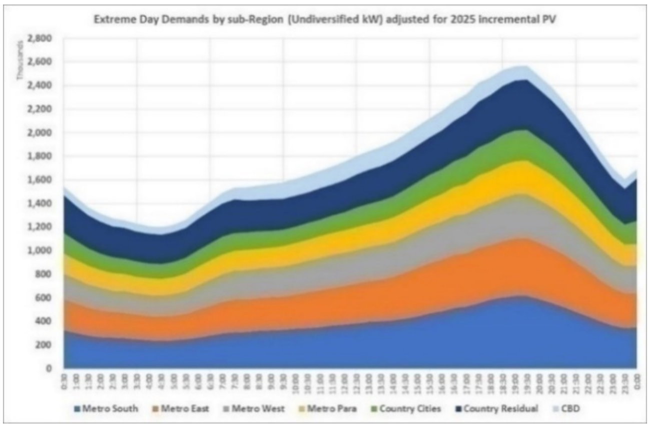


Figure 17B-28: Extreme day demands by sub-region forecast for 2025



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 that whilst the above 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 17B-29 shows the combined effect of solar and a low demand day based on actual data for 20 October 2019. Figure 17B-30, which was prepared 12 months ago, shows the anticipated increase in solar expected to be connected in the network by 2025. 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. The decline in the solar trough in the last 12 months has been dramatic, as shown in the 2019 chart. The 2019 chart includes the major industrial loads which with the CBD provide the only significant net loads across SA during the solar trough on minimum demand days. All other areas are near zero load on minimum days.

Figure 17B-29: **Extreme day demands by sub-region 20 October 2019 (incl. Major Industrial)**

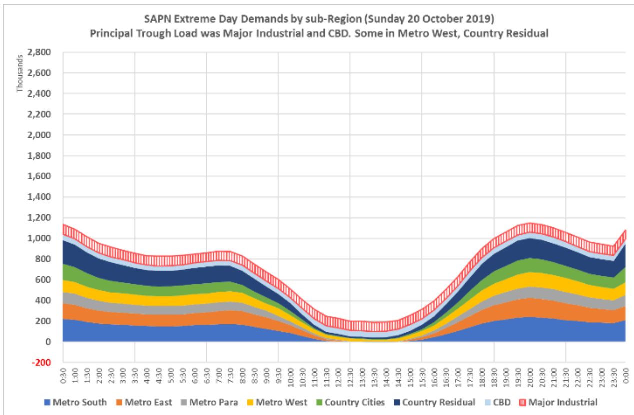
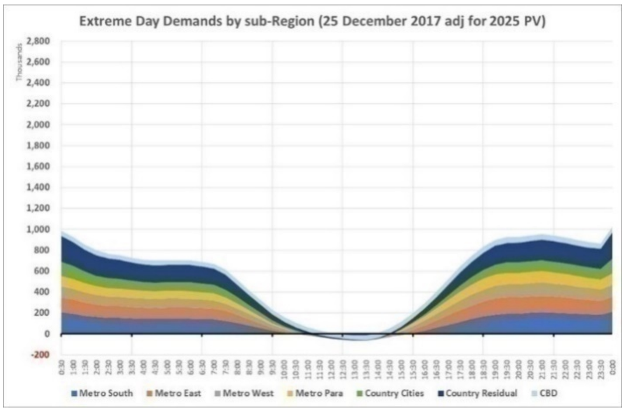


Figure 17B-30: **Extreme day demands by sub-region 25 Dec 2017 adjusted for solar forecast for 2025 (excl. Major Industrial)**



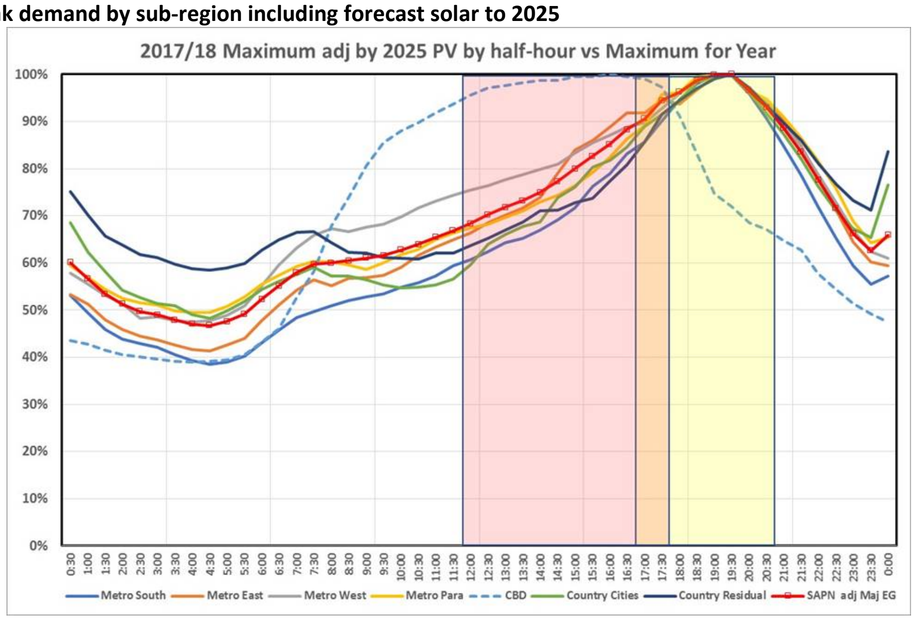
Source: SA Power Networks analysis

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 17B-31 that all the sub-regions have a peak that is experienced around 7:00pm, except for the CBD.

The data demonstrates that most of the state excluding the CBD will have a similar peak demand profile in 2025. The CBD with its higher commercial loads and lower solar penetration has an earlier and flatter peak and could be treated differently.

Figure 17B-31: Peak demand by sub-region including forecast solar to 2025



Seasonal Demand - 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.

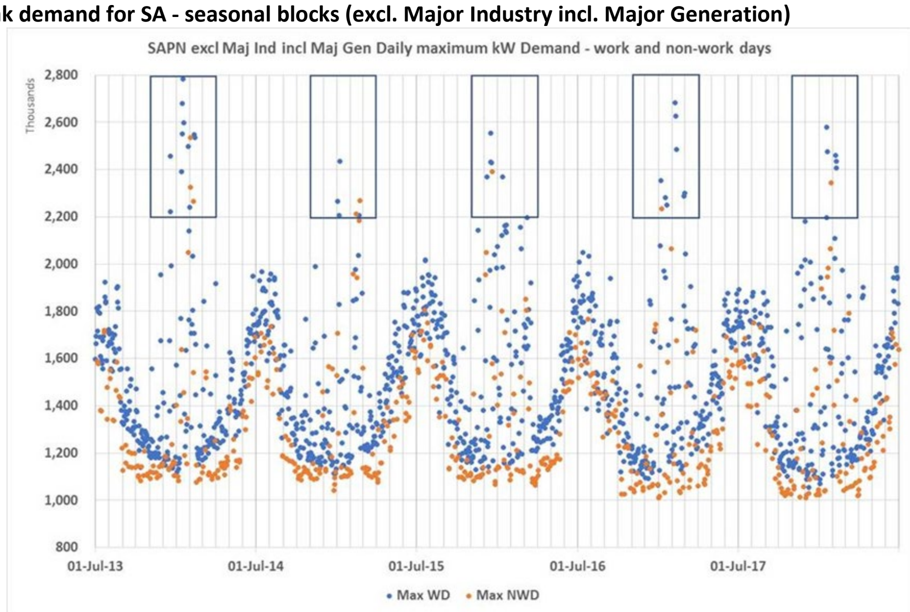
In considering this window, it is necessary to balance the length of the window (in this case five months) against the period that captures the majority of the peaks. Further, the behaviours that a tariff methodology might employ should cover the behaviours of the customers over the period in which the 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)

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

Figure 17B-32: Peak demand for SA - seasonal blocks (excl. Major Industry incl. Major Generation)



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 2015/16 from early November to late March. The Para data above demonstrates that the summer of 2015/16 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.

Figure 17B-33: Peak demand for country – seasonal blocks (excl. country cities)

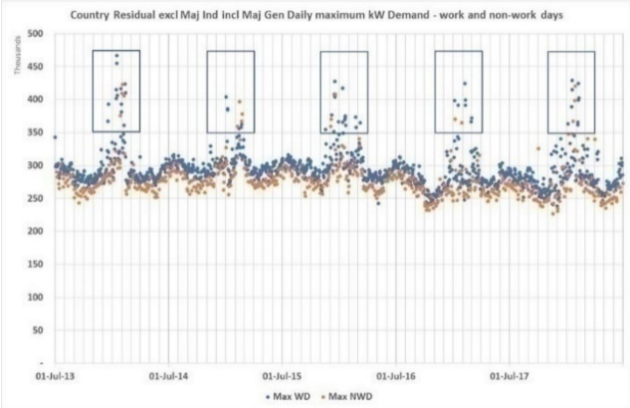
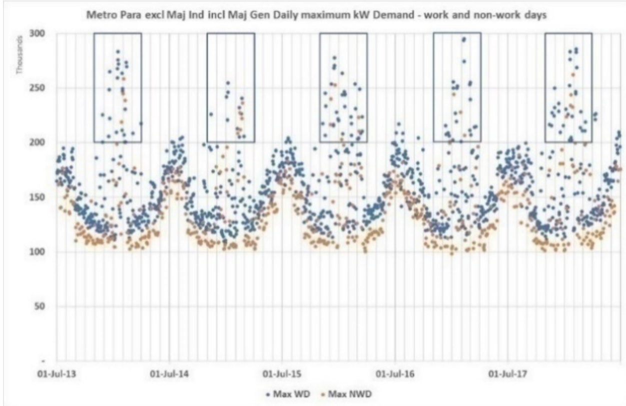


Figure 17B-34: Peak demand for Metro Para – seasonal blocks



Source: SA Power Networks analysis

In conclusion, where it is necessary to determine a period 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.

Peak Demand - workday versus non-workday

Determining the different demands on workdays compared to non-workdays 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.

The following series of charts plot the maximum demands by day, applying a different colour for a workday as compared to a non-workday for the five-year period 2013/14 to 2017/18. If there was a significant separation of the workday and non-workday data, there could be a case for a differentiation in a tariff for workday and non-workday consumption/demand.

Figure 17B-35: CBD - Daily maximum demand work and non-workdays

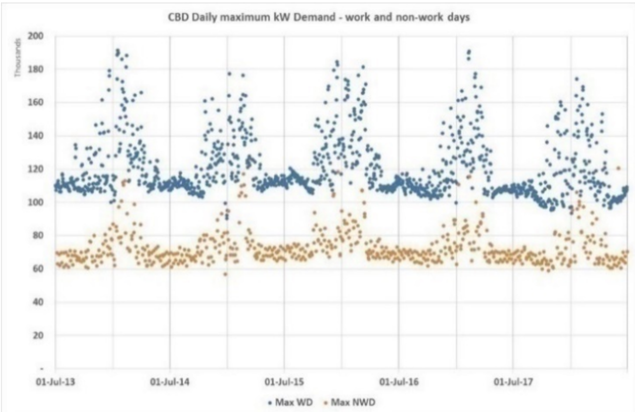
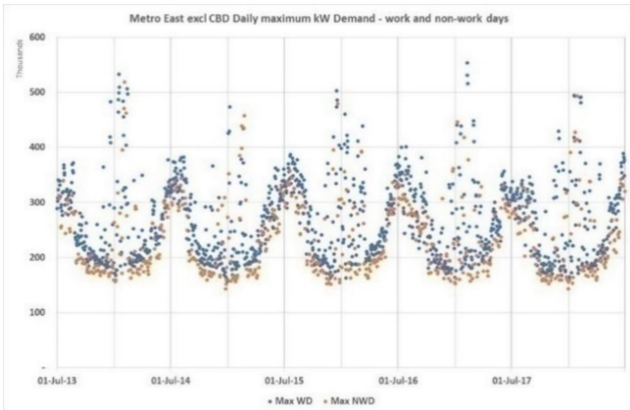


Figure 17B-36: Metro East - Daily maximum demand (excl. major industrial and generation)



Source: SA Power Networks analysis

In Metro West (Figure 17B-38), the data shows a difference between workdays and non-workdays, but there is still some significant overlap on some peak days each year. Similarly, Metro Para (Figure 17B-39) data shows that whilst there is some difference observable between the workday and non-workday, 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 workday and a non-workday suggesting that the circumstances of a workday, or a non-workday are not particular drivers of maximum demand.

Figure 17B-37: Metro South - Daily maximum demand (excl. major industrial and generation)

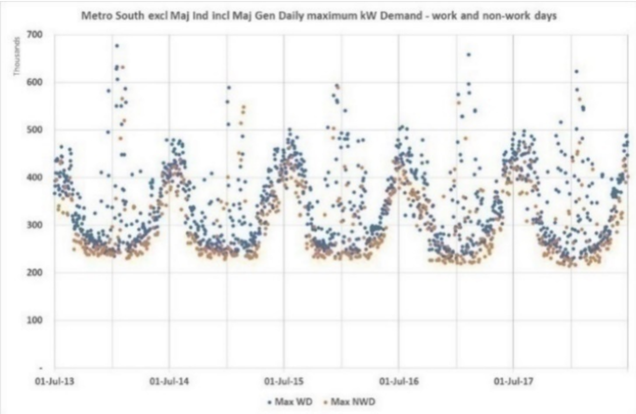
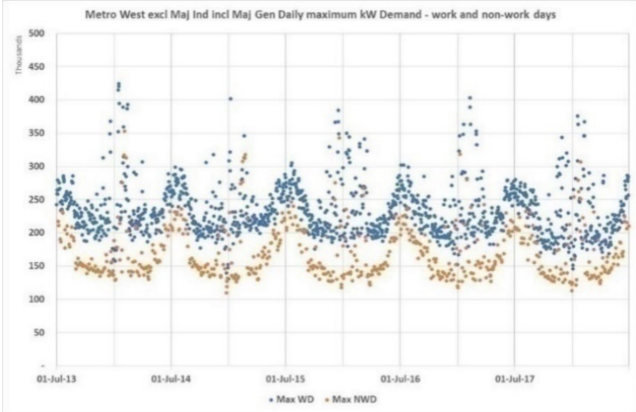


Figure 17B-38: Metro West - Daily maximum demand (excl. major industrial and generation)



Source: SA Power Networks analysis

Figure 17B-39: Metro Para - Daily maximum demand (excl. major industrial and generation)

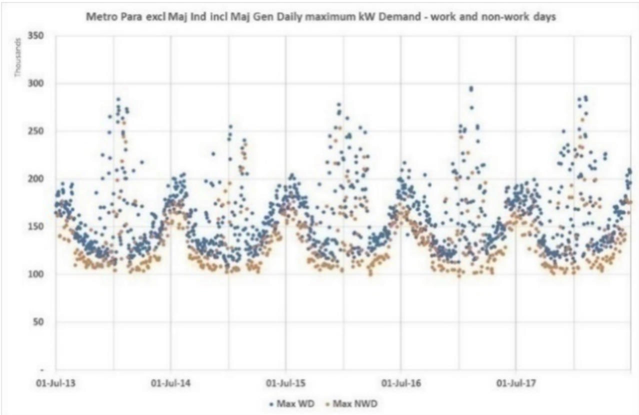
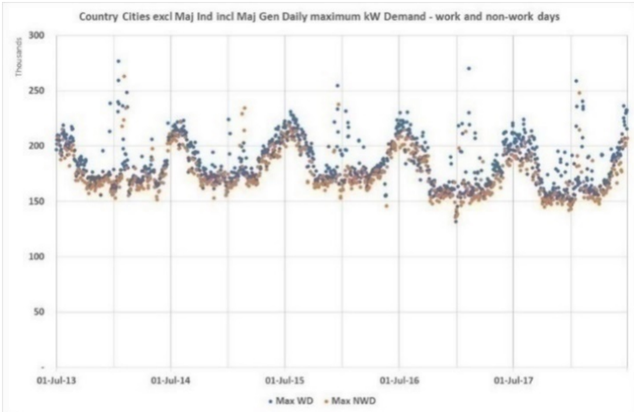
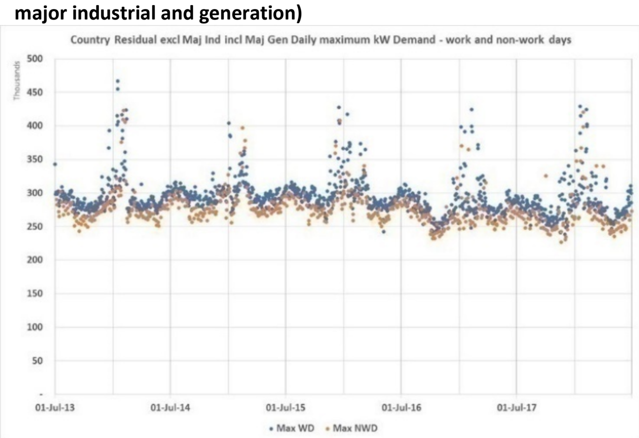


Figure 17B-40: Country Cities - Daily maximum demand (excl. major industrial and generation)



Source: SA Power Networks analysis

Figure 17B-41: Country Residual - Daily maximum demand (excl. major industrial and generation)



Source: SA Power Networks analysis

The CBD however does have sufficient delineation to suggest that the commercial load which is present during a workday is not present to drive demand on the non-workdays. Even though retail and residential loads are present on non-workdays 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. Therefore, it is reasonable to conclude that there is no need for tariff differentiation between workdays and non-workdays in the South Australian customer base except for the CBD sub-region.

17.6.4 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.

- EVs – EV recharging is forecast by AEMO to become an issue with residential customers in the 2025-30 period 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 EVs on OPCL, which provides an opportunity for low-cost recharging for Residential customers using Type 6 meters fitted with OPCL capability.)

  Commercial EV 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 120kVA will have a ToU price. These are likely to be small kerbside facilities with diversity to the neighbourhood.
  - Sites needing more than 120kVA 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 120kVA 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 EV 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.

17.7 Our forecasts

The forecasts that underpin our TSS for the 2020-25 RCP have been constructed, wherever possible, with consideration to the AEMO forecasts that are published annually for the NEM in AEMO's electricity statements of opportunities. As discussed in Section 17.2.6 AEMO Analysis, the terminology in the most recent electricity statement of opportunities, the 2019 ESOO, has been updated to reflect a CENTRAL forecast (the base), a SLOW change forecast and a FAST change forecast. Our analysis of the latest forecast from AEMO indicates that there are only minor differences between the data we have used for our forecasts compared with those which we used in our Original Proposal TSS. Therefore, these changes have not been reflected in our forecasts below which remain based on the 2018 ESOO data.

Our forecasts are summarised in the following categories:

- Customer growth forecasts
- Energy volumes carried on our distribution network
- Co-incident demand
- New technologies including solar and batteries

17.7.1 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 17B-3) 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 17B-3: Forecasts of customer numbers (based on 2018 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	84,159	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 supplied 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. Total may not add due to rounding.

17.7.2 Energy volumes carried on our distribution network

In this section, SA Power Networks has set out the energy volumes forecasts including forecasts for residential and business for the 2020-25 RCP. 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 2018 ESOO.

The 2018 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 EVs

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

17.7.2.1 Population and connection growth

Population and connection growth in South Australia is lower than New South Wales, Queensland and Victoria, which is demonstrated in Table 4.

Figure 17B-42: AEMO forecast connections growth by region

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 2018 ESOO page 26

17.7.2.2 Small scale embedded technologies solar growth

Solar is expected to continue to grow in the South Australian market. AEMO recognises that 30% of customers in South Australia already have a solar installation.[21]

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.[22]

17.7.2.3 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.

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

[22] *ibid page 27*

- EVs - electrification of transport, as projected by CSIRO will likely increase consumption but only after 2030, when EVs are forecast to become cost-competitive with other transport alternatives. AEMO's 2018 ESOO is forecasting that EVs 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 EV 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.

17.7.2.4 Developing the energy volume forecasts for SA Power Networks customers

AEMO has developed an energy volume forecast for South Australia[23] 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. This is slightly different to the energy that SA Power Networks needs to deliver to its customers.

AEMO 2018 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 2018 ESOO forecast for South Australia.
- The adjusted AEMO 2018 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.

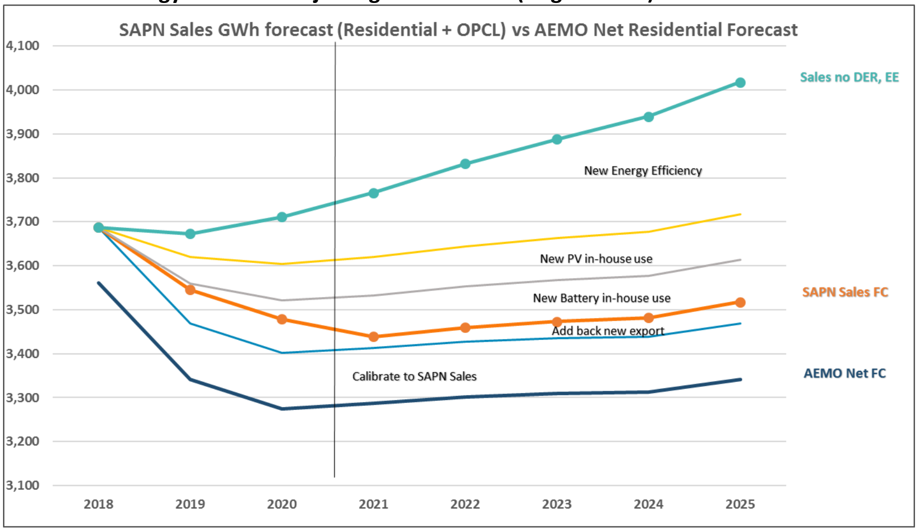
Energy volumes forecasts are prepared for residential and business customer segments to demonstrate the different effects of growth and disruptive technologies such and energy efficiency, solar and batteries.

Residential energy volume forecasts

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

[23] AEMO, 2018 ESOO, page 36.

Figure 17B-43: SA Residential energy forecast - Adjusting AEMO ESOO (August 2018)



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 17B-44: SA Power Networks – Residential Volumes History and forecasts in GWh

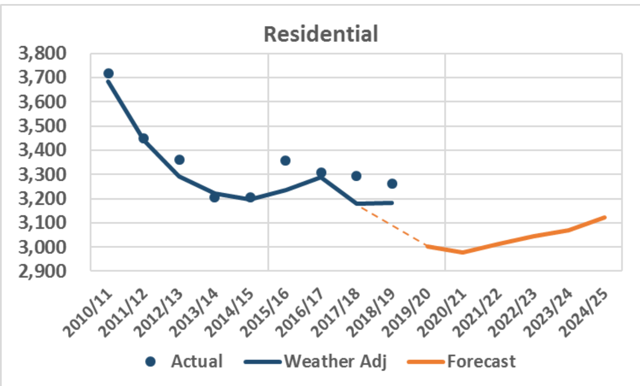
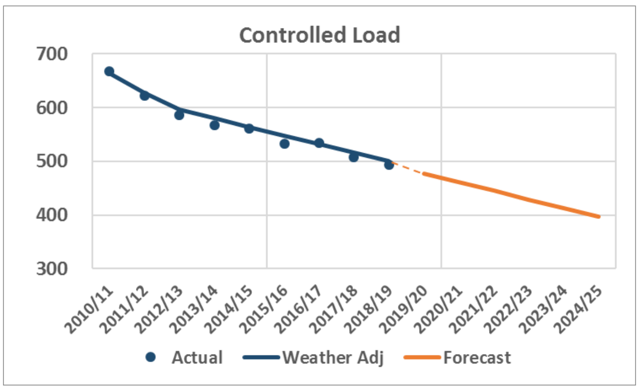


Figure 17B-45: SA Power Networks – Off-peak Controlled Load Volumes History and forecasts in GWh

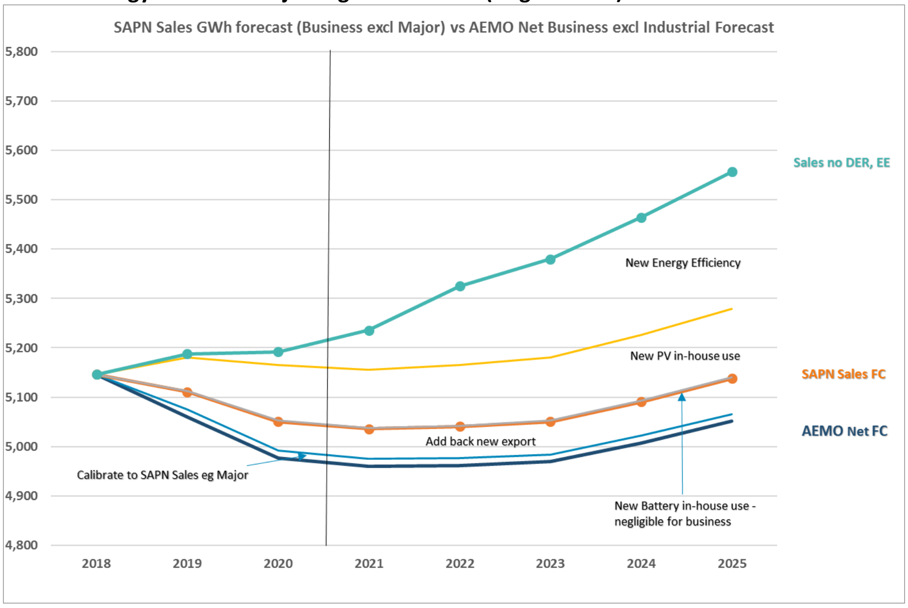


Source: SA Power Networks analysis

Business energy volume 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.

Figure 17B-46: SA Business energy forecast - Adjusting AEMO ESOO (August 2018)



Source: SA Power Networks analysis

The AEMO 2018 ESOO 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.

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 17B-47: SA Power Networks – LV and HV Business Energy volumes history and forecasts in GWh

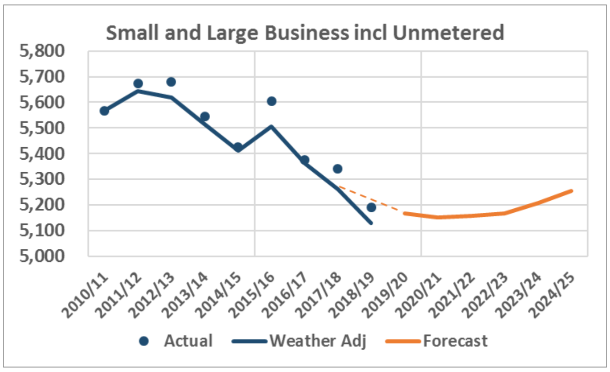
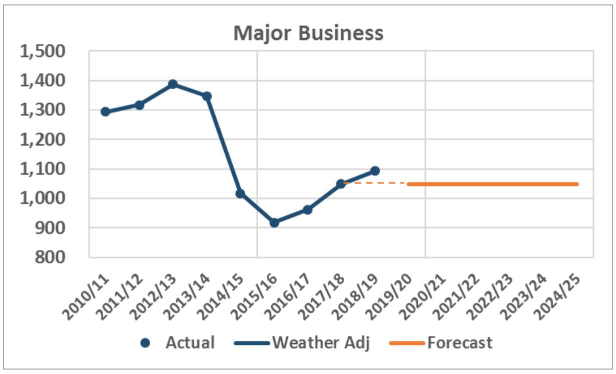


Figure 17B-48: SA Power Networks – Major Business Energy volumes history and forecasts in GWh



SA Power Networks volume forecasts

Table 17B-4: SA Power Networks volume forecast (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 forecast	**3,478**	**3,439**	**3,460**	**3,473**	**3,482**	**3,518**
Comprising:						
Residential	*3,001*	*2,978*	*3,014*	*3,044*	*3,069*	*3,121*
OPCL (Hot Water)	*477*	*461*	*445*	*429*	*413*	*397*
Business						
AEMO forecast	4,977	4,960	4,962	4,969	5,007	5,051
Adjustments[1]	189	191	194	196	199	201
SA Power Networks volume forecast	**5,166**	**5,151**	**5,156**	**5,166**	**5,206**	**5,253**
Comprising:						
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	2801	3195	3203	3236	3273
Adjustments[2]	(1,723)	(1,752)	(2,146)	(2,154)	(2,187)	(2,224)
SA Power Networks volume forecast	**1,049**	**1,049**	**1,049**	**1,049**	**1,049**	**1,049**
Comprising:						
Zone Substation	*495*	*495*	*495*	*495*	*495*	*495*
Sub-Transmission	*554*	*554*	*554*	*554*	*554*	*554*
Total						
SA Power Networks volume forecast	**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

17.7.3 Co-incident 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.

SA Power Networks co-incident demand for the period 2011 to 2025 is summarised in the table in the following page.

Table 17B-5: 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 (operational)	3,287	2,885	2,977	3,162	2,750	2,854	3,004	2,884	3,140						
SA 10 % POE Forecast (AEMO)										3,193	3,211	3,205	3,222	3,224	3,229
SA 50% POE Forecast (AEMO)										2,950	2,958	2,954	2,969	2,992	2,985
SA Power Networks Actual Peak MW	3,031	2,628	2,711	2,920	2,512	2,620	2,736	2,649	2,963						
SA Power Networks 10% POE Forecast (Co-incident Transmission Exits, DR adj)			3,079	3,132	2,969	3,137	3,200	3,038	3,163	3,149	3,147	3,146	3,145	3,143	3,142
SA Power Networks 50% POE Forecast (Co-incident Transmission Exits, DR adj)										2,906	2,904	2,903	2,902	2,900	2,899
Difference SA AEMO and SA Power Networks 10% POE forecast										44	64	59	77	81	87
Difference SA AEMO and SA Power Networks 50% POE Forecast										44	54	51	67	92	86

Source: SA Power Networks analysis of AEMO and other data

The SA Power networks 10% POE forecast includes adjustments for weather and demand response (**DR**) at all transmission exits. The actual shown in the row above the 10% POE forecast includes of weather impacts, demand response and adjustments for outages.

The difference between the AEMO 2019 ESOO SA 10% POE/50% POE MW forecast and the SAPN 10% POE/50% POE co-incident MW forecasts increase from 2021 when the SA (AEMO) forecasts presumably allow for growth of a customer connected to the transmission network.

17.7.4 New technology including solar and batteries

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

Table 17B-6: AEMO Forecasts for solar and battery installation (CSIRO moderate case)

	2019 Central Case						2019 Step Change		2018 Moderate	
	2020	2021	2022	2023	2024	2025	2025	Vs Central	2025	Vs Central
Solar Effective Capacity (MW)										
Residential	996.9	1,006.3	1,014.1	1,024.3	1,029.3	1,034.3	1,469.6	435.3	1,034.2	-0.1
Business	223	276.1	310.8	320.2	322.0	323.1	457.9	134.8	291.9	-31.2
Total Customer solar <100 kW	**1,219.9**	**1,282.4**	**1,324.9**	**1,344.5**	**1,351.2**	**1,357.4**	**1,927.4**	**570.0**	**1,326.1**	**-31.3**
PV Non-scheduled generation (>100 kW)	60.5	59.9	59.3	58.7	58.1	57.5	129.1	71.6	175.6	118.1
Total solar MW	**1280.4**	**1342.3**	**1384.2**	**1403.2**	**1409.4**	**1414.9**	**2056.5**	**641.6**	**1501.7**	**86.8**
Battery Effective Capacity (MW)										
Residential	79.7	161.8	160.2	158.6	157.0	155.4	476.2	320.8	169.1	13.7
VPP	16.8	33.2	33.1	28.9	25.4	31.0	727.8	696.8	-	-31.0
Business	4.3	4.3	5.1	6.0	7.0	8.2	24.0	15.9	5.3	-2.9
Total Battery MW	**100.8**	**199.4**	**198.4**	**193.5**	**189.4**	**194.6**	**1,228.0**	**1,033.4**	**174.4**	**-20.2**
Battery Effective Capacity (MWh)										
Residential	207.2	161.3	159.6	221.1	331.8	476.2	1238.1	761.9	439.8	-36.4
VPP	43.6	86.3	85.9	75.0	66.1	80.5	727.8	647.3	-	-80.5
Business	10.8	7.2	10.1	12.7	16.9	24.0	61.7	37.7	13.7	-10.3
Total Battery MWh	**261.7**	**254.8**	**255.6**	**308.9**	**414.8**	**580.7**	**2,027.6**	**1,446.9**	**453.5**	**-127.2**

Source: AEMO forecast. Totals may not add due to rounding.

The data presented Table 17B-6 provides a summary of the AEMO solar and battery installation MW forecast. This data shows the 2019 central case and the 2018 moderate case forecast are relatively similar, with the 2019 central case solar forecast decreasing by 86.8MW and battery installation increasing by 20.2MW. The significant movement in AEMO forecasts are related to the 2019 step change. This step change forecasts continuing solar penetration and a rapid increase in the take-up of batteries, particularly in for residential and VPP customers. The variance between the step change forecast and the 2019 central case would see a further 641.6MW of solar and 1,033.4MW of battery installation by 2025. As mentioned previously (Section 17.2.6 AEMO Analysis) we have retained the 2018 moderate case for our forecast volumes in our Revised Proposal.

17.8 Tariff design, development and assignment

17.8.1 Types of tariffs and 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).

17.8.1.1 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 120kVA. Following extensive engagement, we are not requiring an anytime demand charge for residential customers or for small business customers less than 120kVA.

17.8.1.2 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.

17.8.1.3 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.

17.8.2 How we develop the tariffs for the 2020-25 RCP

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
- Large business Major, 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)

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.

17.8.2.1 Background to the 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:

- Our customer impact principles (Section 17.3)
- Changes we are facing in the use of energy by our customers (Section 17.6)
- The need to continue tariff reform as required by the AER (Section 17.5)
- Feedback from engagement with our customers (Section 17.4 and the Customer and stakeholder engagement report)
- Analysis of the workday and non-workday differences across tariff classes and locations discussed in 17.6.3.

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.

17.8.3 Assigning customers to tariffs

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 four 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) for upstream assets
- An anytime annual demand charge that recovers the costs of local connection/network assets used by that customer
- 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 accumulation (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 the Rules[24] and any directions provided in the AER's Final Decision (revenue determination). The process which SA Power Networks follows to assign customers to tariffs is detailed in our TSS (Part A).

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 (default 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 120kVA will be assigned to the small business ToU + MD tariff
- all new/alterations to supply small businesses requiring new 120kVA or more will be assigned to the small business ToU with maximum demand tariff, from July 2020.

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.

Where a small customer has a Type 6 meter replaced with a Type 4 meter, the customer will be reassigned to the ToU tariff.

Alterations to supply/new customers do not include a change in the name of the existing account holder.

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[24] NER, clause 6.18.4

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 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.

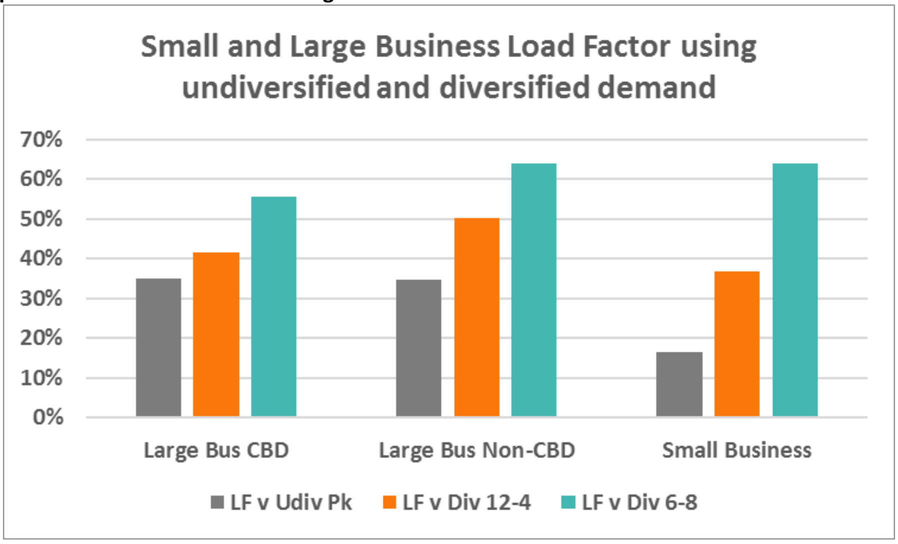
In considering these small business customers, we have had regard to the various characteristics of energy consumption by customers which have some of the attributes of a large business customer. However, they are not a large business customer by the nature of their consumption being less than the threshold 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 Figure 17B-49. This figure 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 17B-49: 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 service 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.

17.8.4 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 residential tariff structures have been simplified to improve cost reflectivity and for ease of understanding. We have outlined the 2020-25 tariff structures and charging parameters in our TSS Part A, Section 17.4. The changes proposed for residential tariffs include:

- 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.

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).

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 for 2020/21 are set out in Table 17B-7. The prices are indicative, and include transmission and PV FiT recovery as well as distribution (referred to as Network Use of System (**NUoS**))

Table 17B-7: Residential tariffs 2020/21 NUoS Forecast

			$pa	$/kW pa	c/kWh	c/kWh	c/kWh	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)	170	-	-	-	-	13.2
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).	170	-	16.3	7.2	4.1	-
Residential Prosumer	Supply charge + ToU + average summer peak demand monthly charge	Remotely read interval meter (Type 4)	170	102*	10.2	4.8	2.9	-

* Applied as $20.3/kW per month, November to March, on maximum average kW 5pm to 9pm for the month.

17.8.5 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.[25] 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. 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 (central standard time). Retailers are asked to randomise the start of these modern meters by a minimum of one hour.

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.

[25] 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).

- **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.

Table 17B-8: Off-peak controlled load tariffs – NUoS Forecasts

			$pa	c/kWh	c/kWh	c/kWh	c/kWh
Residential Tariff	**Tariff Structure**	**Metering**	**Supply Charge**	**Peak Usage Charge**	**Off-peak usage charge**	**Solar sponge usage charge**	**Usage Charge**
Off-peak controlled load	Flat rate	SAPN meter (Type 5, 6)	-	-	-	-	7.2
Off-peak controlled load	Peak and off-peak rates	Retailer interval meter (Type 4 only)	-	16.3	7.2	4.1	-

17.8.6 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-workdays. 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 workdays (excluding the peak times)
- Off peak charge: 9:00pm to 7:00am workdays 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 120kVA in demand. These customers represent a few percent of small business only. The Small business tariffs for 2020/21 are set out in Table 17B-9.

Table 17B-9: Small business tariffs - 2020/21 NUoS forecast

Residential Tariff	Tariff Structure	Metering	$pa Supply Charge	$/kW pa Actual Peak Demand Charge	$/kW pa Anytime Maximum Demand Charge	c/kWh Peak Usage Charge	c/kWh Shoulder usage charge	c/kWh Off-peak usage charge	c/kWh Usage Charge
Small business Single rate	Supply charge + flat rate	Accumulation meter (Type 6)	185	-	-	-	-	-	13.1
Small business Two rate	Supply charge + peak and off-peak rates	Accumulation meter (Type 6)	185	-	-	14.7	-	7.7	-
Small business ToU <120 kVA	Supply charge + ToU rates	Type 4 Interval meter - remotely read Type 5 Legacy meter - manually read	185	-	-	19.4	13.7	7.7	-
Small business ToU and MD	Supply charge + anytime demand rates + ToU rates	Interval meter (Type 4)	185	-	26.1	16.6	11.8	6.7	-
Small business SBD Transition	Supply charge + peak demand rates + ToU rates	Interval meter (Type 4)	1,015	12.0 per month	6.0 per month shoulder	-	-	-	7.9
Streetlights and unmetered loads	Unmetered	Unmetered (Type 7)	-	-	-	-	-	-	8.9

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 120kVA - 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[26] metering, as such installations cannot exceed 120kVA.
- Small business with demand greater than 120kVA – 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.

17.8.7 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:

- **Supply charge** – varies based on supply point. Structure does not change from that previously offered. This recovers some of the connection costs.
- **ToU energy** – based on peak and off-peak usage times where peak is 7:00am to 9:00pm local time on workdays (excludes public holidays), plus from 5:00pm to 9:00pm on non-workdays during November through March; and off-peak is all other times.

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

- **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 workdays for the CBD; and
  - in a 4-hour interval between 5:00pm and 9:00pm on workdays in non-CBD areas.
- **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.

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.

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 150% 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 150% of that, ie $30/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 the differences driven by the load in the Adelaide CBD. The legislative requirement[27] 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 workdays and non-workdays for the CBD as identified in 17.6.3.2. 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. 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.

The large business tariffs for 2020/21 are set out in Table 17B-10, Table 17B-11 and Table 17B-12.

Table 17B-10: Large LV business tariff 2020/21 NUoS Forecast (CBD and Non-CBD)

			$pa	$/kVA pa	$/kVA pa	$/kVA pa	c/kWh	c/kWh	c/kWh	c/kWh
Residential 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/ Type 5 Legacy	2,500	87.0	-	35.0	5.9	-	3.9	-
Large business ToU annual demand - monthly	Supply charge + annual demand + ToU rates	Type 4 Interval/ Type 5 Legacy	2,500	-	26.1 Per month	35.0	5.9	-	3.9	-
Large business ToU annual demand transition	Supply charge + annual demand + ToU rates	Type 4 Interval/ Type 5 Legacy	1000	-	12.0 Per month	6.0 Per month	-	-	-	7.7
Large business Single rate transition	Supply charge + single rate	Accumulation meter (Type 6)	170	-	-	-	-	-	-	15.5
Large business two rate transition	Supply charge + two rate	Accumulation meter (Type 6)	170	-	-	-	-	17.4	8.9	-

[27] *Electricity Act 1996 (SA) (as amended), section 35A (2).*

Table 17B-11: Large HV Business tariffs 2020/21 NUoS Forecast (CBD and Non-CBD)

			$pa	$/kVA pa	$/kVA pa	$/kVA pa	c/kWh	c/kWh	c/kWh	c/kWh
Residential 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 HV business Annual demand	Supply charge + annual demand + ToU rates	Interval meter, - remotely read (Type 4)	15,000	74.0	-	35.0	3.5	-	2.3	-
Large HV business Actual demand - Monthly	Supply charge + actual demand + ToU rates	Interval meter, - remotely read (Type 4)	15,000	-	22.2 Per month	35.0	3.5	-	2.3	-
Large HV business Annual demand - Monthly <500 kVA	Supply charge + annual demand + ToU rates	Interval meter, - remotely read (Type 4)	2,500	-	26.1 Per month	35.0	5.7	-	3.7	-
Large HV business HBD Transition	Supply charge + annual demand + ToU rates	Interval meter, - remotely read (Type 4)	1,000	-	12.0 Per month	6.0 Per month	-	-	-	7.5

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

Table 17B-12: Non-location Major business 2020/21 NUoS Forecast

			$pa	$/kVA pa	$/kVA pa	$/kVA pa	c/kWh
Residential Tariff	Tariff Structure	Metering	Supply Charge	Annual Peak Demand Charge	Actual Peak Demand Charge	Anytime Maximum Demand Charge	Usage Charge
Zone Substation Agreed Demand	Supply charge + annual demand + ToU rates	Interval meter, - remotely read (Type 4)	Individually calculated	52.0	-	25.0	0.8
Sub-transmission Agreed Demand	Supply charge + actual demand + ToU rates	Interval meter, - remotely read (Type 4)	Individually calculated	38.0	-	14.0	0.7

17.8.8 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 RCP.

We are also proposing to trial two of the residential tariffs proposed for the 2020-25 RCP. 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).

17.9 What do these tariffs mean for customers

In this section 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. 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.

17.9.1 Possible retailer responses, implications for customers

Network tariffs are generally incorporated into small customers' bundled retail tariffs by the retailer and passed through to large businesses. Retailers have faced market-based energy costs since the NEM started, particularly where the customer has a Type 4 meter. The small customer tariffs proposed here will add another dimension to the costs faced by retailers.

We expect that some retailers will elect to minimise their network costs where possible, including:

- Adjusting the time clocks on their Type 4 meters for hot water (OPCL), to shift any load currently in the 10:30 pm to 11:30 pm (EST) window into the 11:30 pm and beyond off-peak period.
- Depending on the energy price available during the solar sponge, shift some of the hot water (OPCL) from the off-peak period into the lower priced solar sponge.
- Select opt-in tariffs for Type 4 meter customers where that tariff gives a significant benefit over the default tariff assignment.

These actions should not affect customers. Customer prices may reduce as a result, but that is likely to vary with competition. We note that retailers are not obliged to pass-through our network tariff structure into their tariff offers, nor their wholesale energy price structures. They may choose to do so, but they are not obligated to. Retailers must deal with competition from other retailers and comply with the AER's default market offer requirements for small customers.

Retailers can also use the TOU OPCL network tariff for residential customers for whatever appliances they wish if Type 4 meters are available. Retailers could expand the devices available under their OPCL control to include pool pumps and air-conditioning as well as those appliances currently permitted with Type 6 meter OPCL (eg hot water heating, underfloor heating, battery charging and EV charging). Of course, any OPCL use outside of the designated off-peak and solar sponge price periods will be charged at the peak network price (125% of residential single rate).

At some stage, retail tariff offers to small customers will evolve. Some retailers will develop more complex tariffs sooner than other retailers, and some customers will seek out such offers. However, we expect the significant proportion of Type 4 meter small customers will be happy to remain with simple tariffs, certainly during the initial stages of the 2020-25 RCP. Over time, the demand for and acceptance of cost-reflective prices by customers will increase, if such tariffs provide benefits for customers.

We expect that retailers will offer one or more of the following retail tariff structures to customers:

- A single rate offer to Type 6 meter customers (2-rate for those small businesses with 2-rate meters).
- Similar offers to small customers with Type 4 meters.
- For Type 4 meter customers only,
    - pass-through of the Network TOU tariff combined with the Type 6 single-rate energy offer.
    - pass-through of the Network TOU offer combined with a TOU energy price offer
    - small business might have a transition actual demand offer
    - a different offer which involves the opt-in tariffs eg residential prosumer and small business TOU with maximum demand.
    - A lower price where device control is available. This could be an extension of the OPCL tariff, or some other innovative mechanism that the retailer creates.
- Other retail offers.

17.9.2 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 workday and non-workday). 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 EVs. Whilst not proposed to have a significant effect in the 2020-25 RCP, the influence of EVs is forecast to grow, and this tariff will assist in reducing the impact of an otherwise anticipated EV 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.

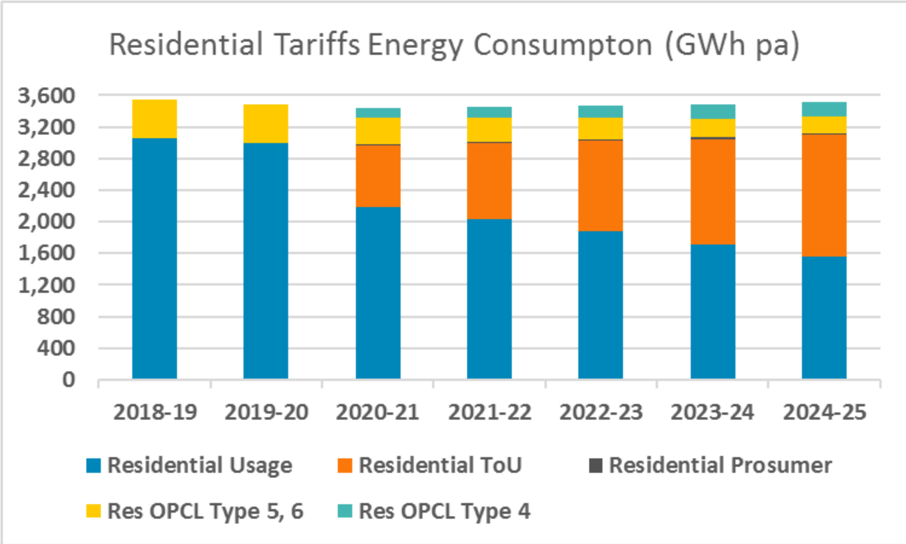
  This is a new tariff for the 2020-25 RCP which introduces a peak demand charge for a four-hour window between 5:00pm and 9:00 pm each day and measured as the highest average daily demand for the month, during the months of November to March in each billing year (financial year ending June). The peak 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. 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. Such arrangements add cost and detract from the signals for an opt-in tariff aimed at a Prosumer and/or a retailer. The tariff proposed has higher charges in summer from the simple use of monthly demand in November through March.

  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.

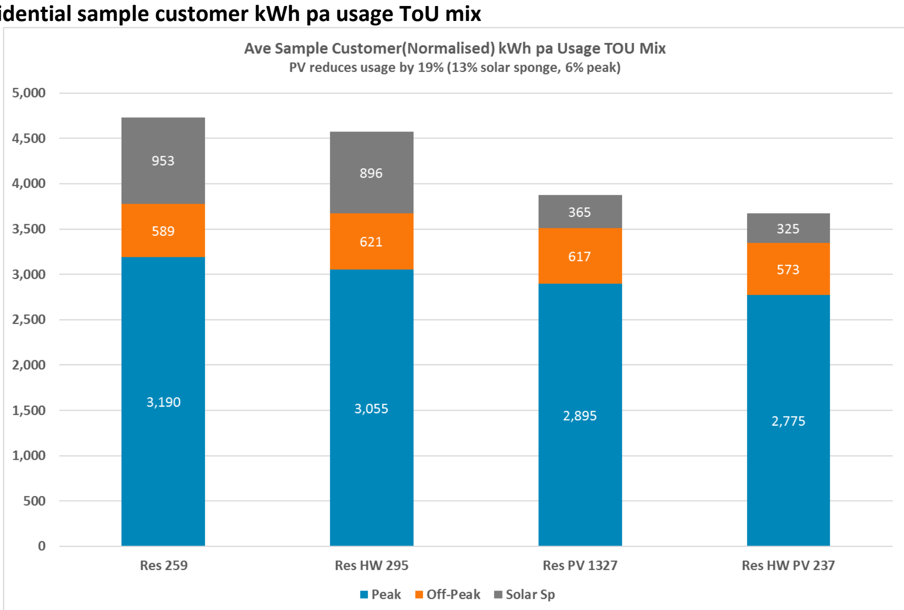
Figure 17B-50: Residential tariff forecast energy consumption by class



Source: SA Power Networks analysis

Four different samples of residential customers with Type 4 meters were prepared for the AER in response to an information request. The average usage in 2018/19 over the three TOU periods is shown in Figure 17B-51. This data has been normalised to enable the four samples to reflect a similar size of maximum demand customer. The principal difference in annual usage between with PV and without PV customers is the solar sponge usage, with some reduction in the 'peak' period abutting the solar sponge resulting from in-house use of solar PV.

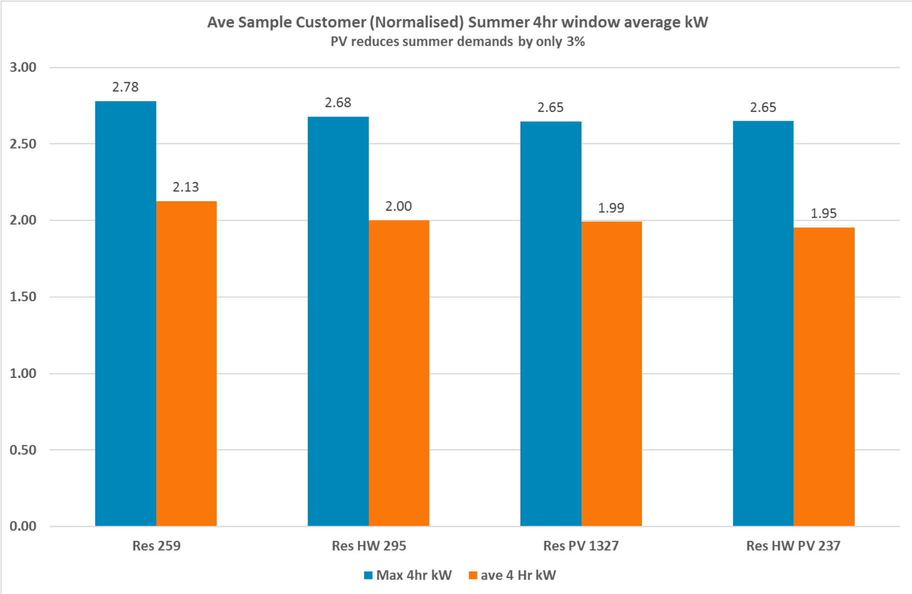
Figure 17B-51: Residential sample customer kWh pa usage ToU mix



Source: SA Power Networks analysis

Figure 17B-52 shows the summer demands for the four residential customer samples. The demand reflects the average four-hour demand between 5:00pm and 9:00pm during summer. The average (orange column) is the average of each of the 5 month's daily maximum whilst the maximum is the highest daily maximum over the five months. The 'with PV' sample has slightly lower demand than the 'no PV' sample. These are the likely customer billing demands; they are not the 'after-diversity' outcomes. Figure 17B-55 shows the after-diversity average outcome per customer. Of course, with a four-hour average demand measure, the diversity between customers is largely incorporated into that average number and better reflects the contribution to diversified peak by the individual customer than the single half-hour average maximum does.

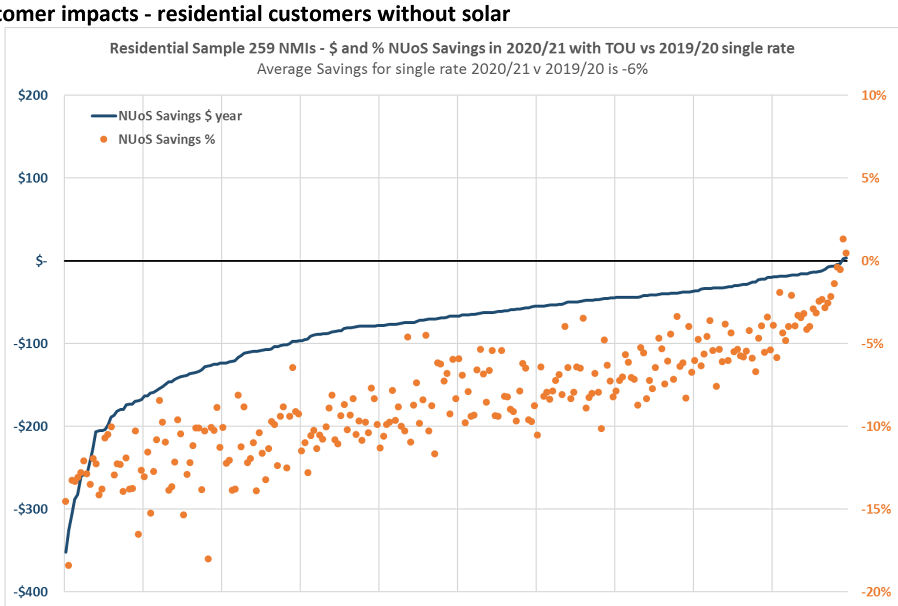
Figure 17B-52: Residential sample customer summer 4-hour window average kW



Source: SA Power Networks analysis

Customer impacts for residential customers is demonstrated below. The propeller charts map two parameters for each customer in the sub-class. The blue line represents the outcomes of each individual customer, sort in ascending order of price impact. There is a corresponding orange dot for each customer that represents the percentage change that the proposed tariff will cause to the customers total network charge.

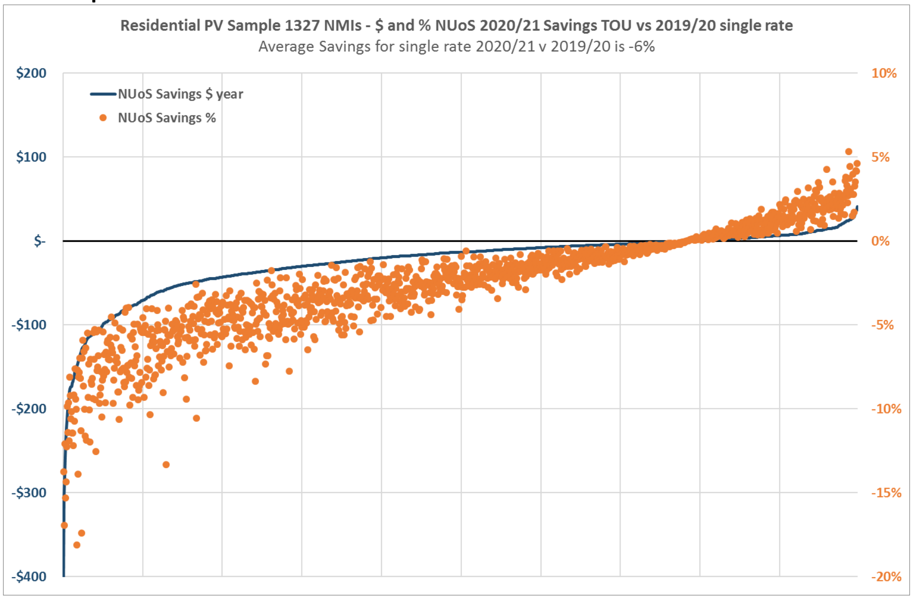
Figure 17B-53: Customer impacts - residential customers without solar



Source: SA Power Networks analysis

The prosumer tariff gives another more complex tariff option. The distribution of winners and losers versus the ToU will be symmetrical, with a segment having larger savings that may find the prosumer option attractive. Comparing our sample of residential NMIs (without PV) 12% have NUoS savings on Prosumer versus TOU tariff exceeding 10%. The average savings above 10% saving was 14% (10% of NUoS savings averages about $80 plus GST/customer). For a residential customer with PV, 8% have NUoS savings exceeding 10% on Prosumer. The average saving for these residential PV customers was 13%.

Figure 17B-54: 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. Note that with the Prosumer tariff, the standard deviation in outcomes is larger than with TOU. For customers with PV the standard deviation is triple the TOU outcome, and for customers without PV the standard deviation is double. However, prosumer is opt-in and not a default tariff. Customers/retailers can elect over time whether to use the prosumer tariff.

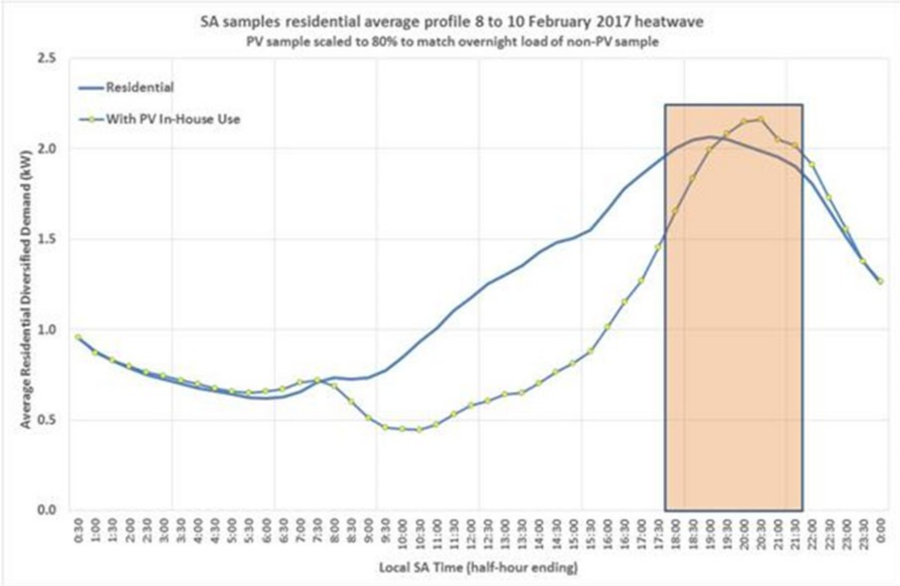
If retailers pass the effect of these network tariffs through to customers, customers may be motivated to change consumption patterns to try to reduce their individual bills. This behaviour will increase the utilisation of the network which will help to lower the future price of electricity for all customers 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 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 result from 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 17B-55 shows the average extreme summer day profiles for households with and without solar.

Figure 17B-55: Residential demand profile with and without solar



Source: SA Power Networks analysis

Figure 17B-55 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 another 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.

SA Power Networks does not determine the value of energy that customers export to the network. In the past, the Essential Services Commission of South Australia 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.

17.9.3 Small Business Tariff Class

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 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, 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.

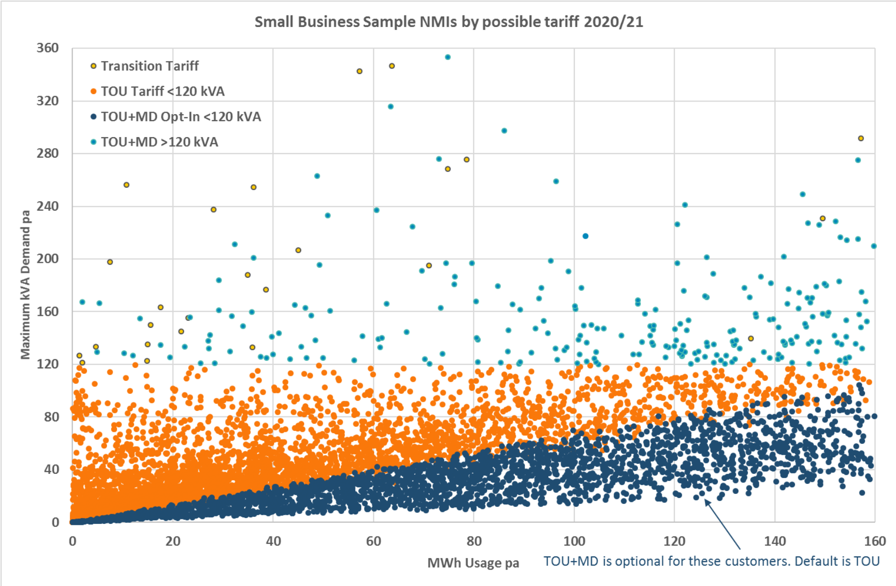
Further, it was noted that within the small business sector, there is a reasonable amount of diversity of demand across this customer class. For example, some small businesses do not operate during normal business 7:00am to 9:00pm peak times, and some do not operate each workday in a week, or each month 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 17B-56) demonstrates. For a given maximum demand, there is a range of energy consumptions that need to be considered in developing tariffs for this class. Customers above 120 kVA have been assigned to a TOU tariff including maximum demand. Below 120 kVA many customers will benefit slightly from an opt-in tariff including maximum demand, but for many the benefit may not be material. Perhaps 10% of customers <120 kVA will get a benefit ranging from $500 to $1500 from the opt-in option.

Figure 17B-56: Small business comparison of demand and energy consumption patterns by customer



Source: SA Power Networks Analysis

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**)

We have chosen the value of 120kVA to differentiate customer groups because:

- it keeps tariffs simple for most small customers;
- a customer above 120kVA tends to dominate the demand on local network assets; and
- different metering installations (with CT transformers) are normally required for customers with demand above 120kVA.

So 120kVA represents a natural boundary for this differentiation.

Figure 17B-57: Small business customers by tariff

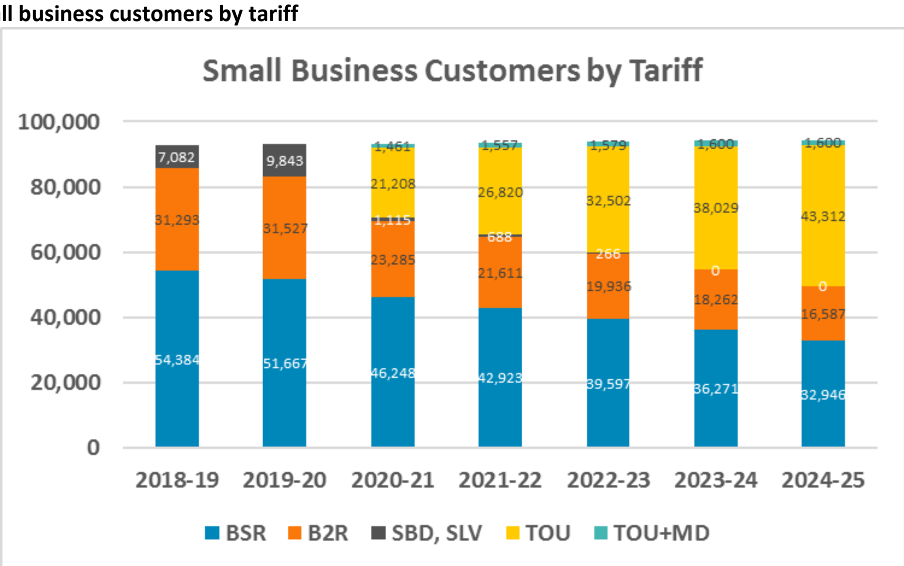
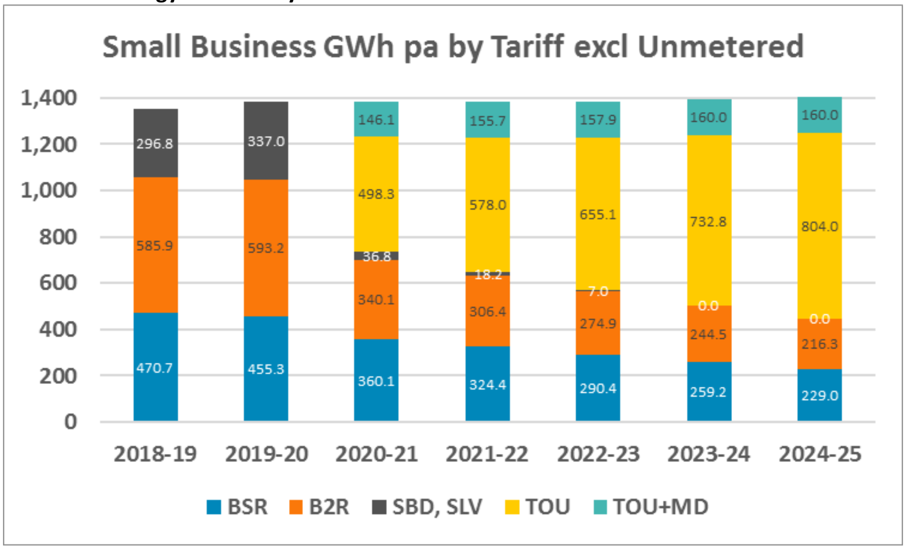


Figure 17B-58: Small business energy volumes by tariff



Source: SA Power Networks analysis

Analysis of the existing tariff structure for small business tariff customers 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 120kVA demand and small business customers with greater than 120kVA demand.
- 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 these observations in a fairer manner, introducing simplicity and more equity in the cost-reflective tariffs applied to this tariff class. 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 workdays 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-workdays 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 workdays and non-workdays in all regions but the CBD.

This tariff also retains an off-peak period during non-workdays 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 120kVA. It is not mandated for small business using less than 120kVA.

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.

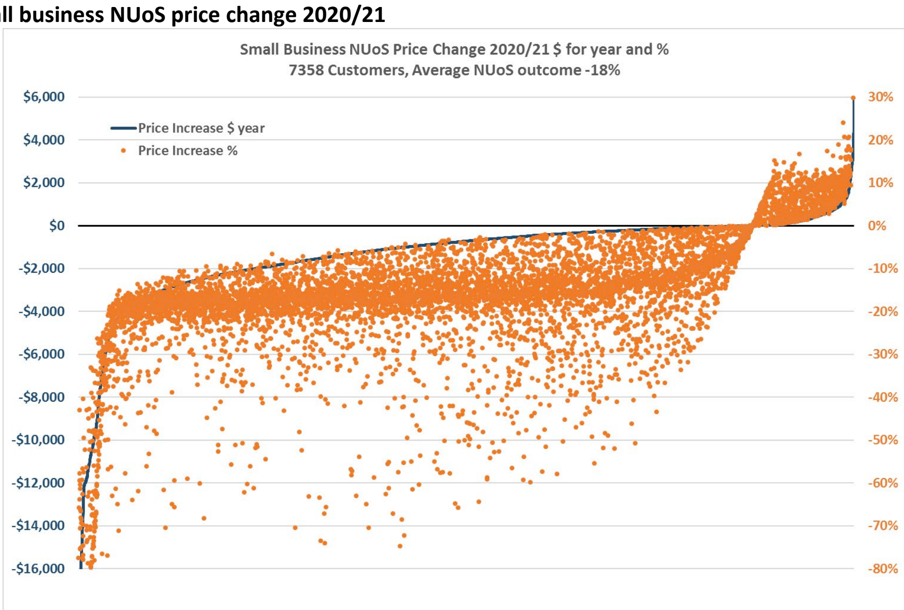
The proposed tariff structure for small business customers with interval meters comprise:

- a supply charge;
- an anytime demand charge (highest 30-minute interval in the last 12 months, customers greater than 120kVA only);
- a peak usage ToU charge (November to March – 5:00pm to 9:00pm);
- a shoulder usage ToU charge (all workdays 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.

For small business single-rate (BSR) and small business two-rate (B2R) customers (with either less than or greater than 120kVA demand) the proposed tariff structure results in a decrease for many customers but recognises that some customers will experience an increase (see Figure 17B-59).

Figure 17B-59: Small business NUoS price change 2020/21



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

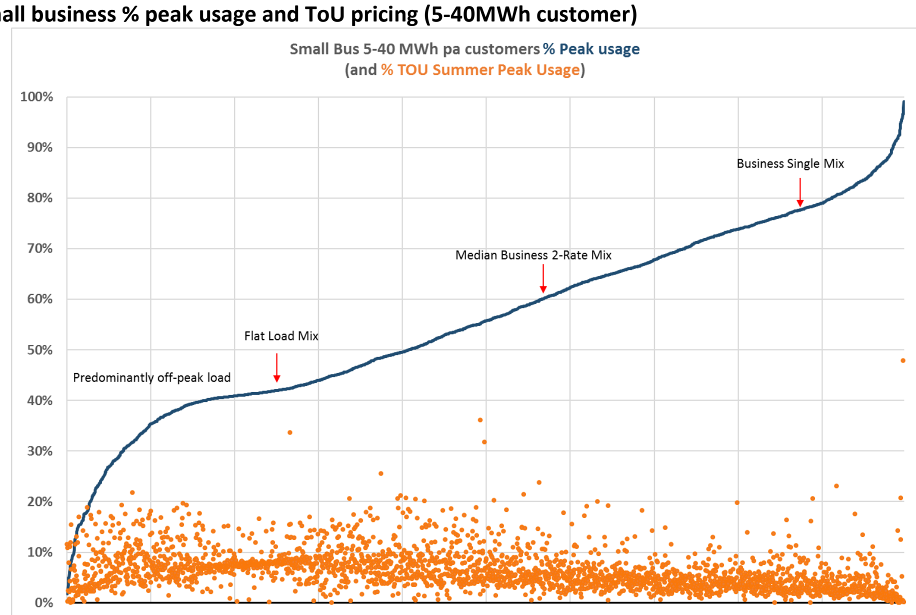
- the supply charge increasing by approximately $100 pa;
- the anytime demand charge for those customers with high demand but low usage; and
- the peak ToU charge those few customers with high proportion of usage in the peak period of 5:00pm to 9:00pm during November to March. It may be that some of 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 transitional arrangements for BSR and B2R customers upon reassignment to small business ToU.

Figure 17B-60 shows the peak usage % and % of ToU summer peak usages for small business customer (5-40MWh customers). The propeller chart shows that 25% of Type 4 metered customers in the sample have a predominantly off-peak usage. About 10% of sample customers have predominantly peak usage, and there is an even distribution of peak to off-peak usage between these two extremes. We price business single on a presumed mix of 77.5% peak and 22.5% off-peak, however we don't know what these customers actually use as they have accumulation meters (single rate). Some will have more peak usage, others less peak usage. It is also a judgement call as to the average business 2-rate mix.

The orange dots show the TOU tariff summer peak usage proportion – the tariff element priced at 150% of business single. The distribution of summer peak usage varies across the sample.

Figure 17B-60: Small business % peak usage and ToU pricing (5-40MWh customer)



Source: SA Power Networks analysis

The percentage increase for most of the SBD and the SBDT customers (whether less than or greater than 120kVA) 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.

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.

17.9.4 Large Business Tariff Class

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

Impact of change in large business LV tariff class

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

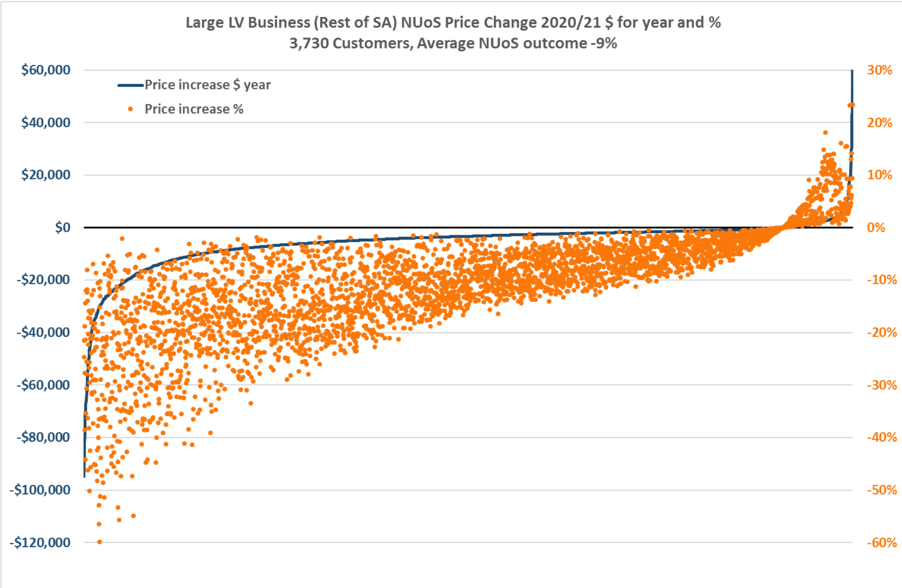
Given the proposal to increase the usage rate of SBD by $10/MWh pa (small business) as a transition measure, we propose to do this as well for large business (BD actual demand). The transition shouldn't take as long or be as severe, as the BD tariff is more closely aligned to the costs of large business. However, 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.

The outcomes for this group of larger consumers is quite different with a significant portion of these customers receiving a price decrease (see Figure 17B-61). 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.

Rest of South Australia (Non-CBD) Impacts

The following analysis identifies the impacts on Large business LV customers outside of the CBD locational zone.

Figure 17B-61: Large LV Business (Rest of SA) NUoS Price Change 2020/21

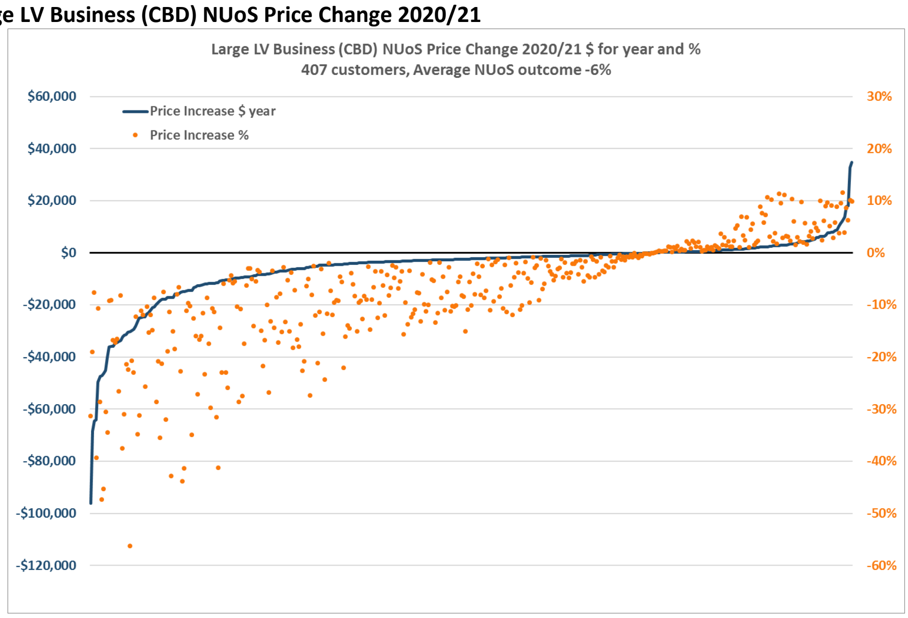


Source: SA Power Networks analysis

CBD Impacts

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

Figure 17B-62: Large LV Business (CBD) NUoS Price Change 2020/21



Source: SA Power Networks analysis

17.9.5 Large Business High Voltage Tariff Class

Impact of change in Large business HV tariff class

The impact of the proposed changes in tariffs for this tariff class are demonstrated for the Large business High Voltage tariff class by non-CBD businesses (eg those in the Rest of South Australia) and CBD businesses.

This tariff class contains 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:

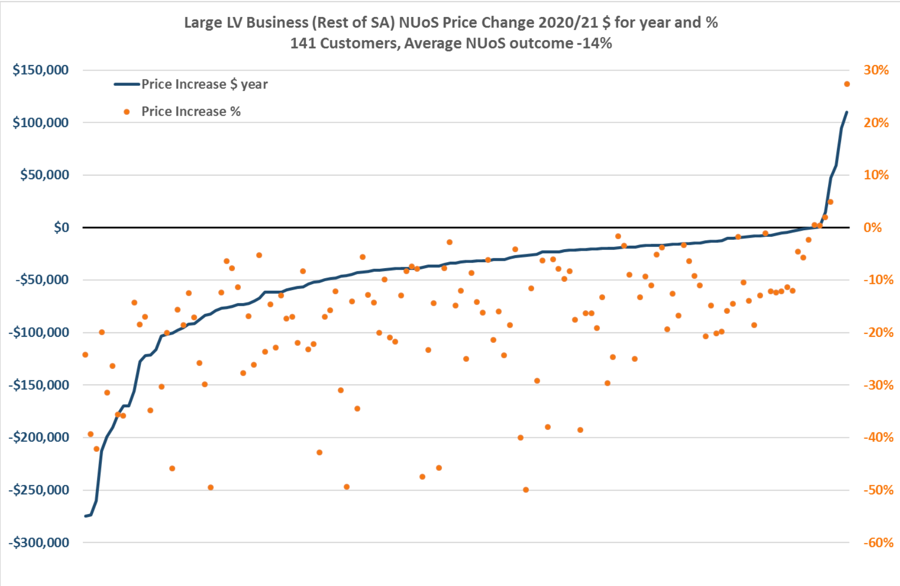
- HV annual demand, with 12-month reset of peak and anytime demands.
- HV actual demand, with 5 months of actual peak HV demand and a 12-month reset of anytime demands.
- The LV actual demand, suitable for those less large businesses (typically less than 500 kVA). The lower supply charge suits those 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.

Rest of South Australia (Non-CBD) Impacts

Many of the 'agreed monthly demand' HBD customers receive an increase reflecting their high demand and low usage patterns. The customer impacts or propeller chart for HV400 (LV priced annual demand), HBD (actual monthly demand) and HV (annual demand) are presented in Figure 17B-63 below.

Figure 17B-63: Large HV Business (Rest of SA) NUoS Price Change 2020/21



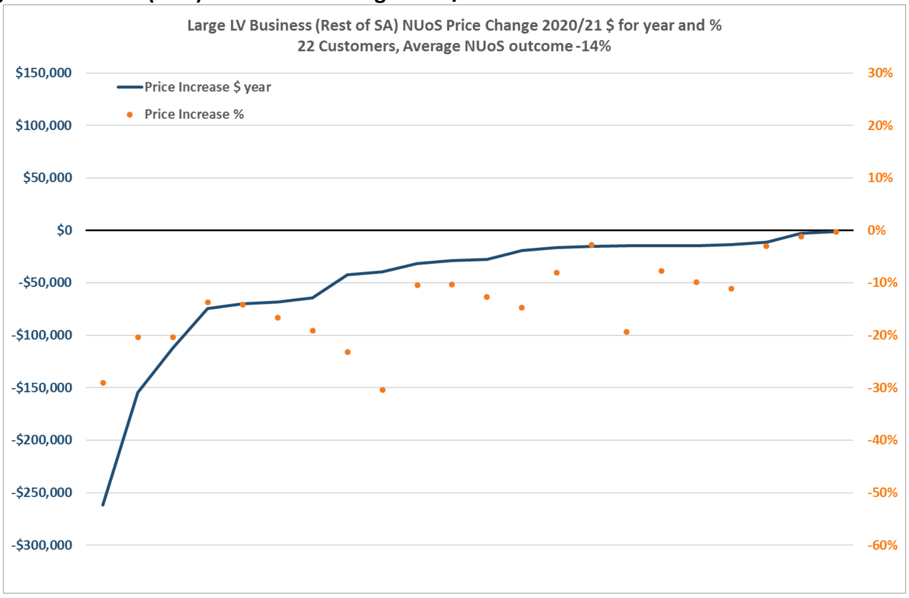
Source: SA Power Networks analysis

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).

Figure 17B-64: Large HV Business (CBD) NUoS Price Change 2020/21



Source: SA Power Networks analysis

17.9.6 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.

17.10 Pricing methodology

17.10.1 Compliance with Rules

This Section demonstrates how SA Power Networks' network tariffs for the 2020-25 RCP 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 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.

17.10.2 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) of clause 6.18.5 of the Rules 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 17B-13.

Table 17B-13: 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	75	10	5
HV business	89	31	5
Large LV business	254	176	44
Small business	301	140	61
LV residential	652	402	244
Total		**759**	

17.10.3 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 17B-14. These values are derived for each system level.

Table 17B-14: 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	**3.6**	**2.6**	0.1					**0.1**	$ 15	0.95	**$ 14.6**
HV bus	**3.5**	**4.2**	0.1	0.1				**0.1**	$ 40	0.90	**$ 37.4**
HV net	**8.8**	**2.3**	0.1	0.2	0.1			**0.5**	$ 56	0.90	**$ 50.7**
LV bus	**40.4**	**2.0**	0.6	1.1	0.6	0.5		**2.8**	$ 69	0.90	**$ 62.4**
LV net	**109.0**	-	1.7	2.8	1.6	1.4	0.0	**7.6**	$ 69	0.90	**$ 62.4**
Totals	**165.4**	***11.1***	***2.6***	***4.2***	***2.3***	***1.9***	***0.0***	***11.1***			

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 17B-15 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 17B-15: Calculated LRMC for SA Power Networks' distribution network

Tariff Class	LRMC, $/kVA per annum	$/kW
Major business – Sub-transmission	$ 14.6	
Major business – Zone Substation	$ 37.4	
Large HV business	$ 50.7	
Large LV business	$ 62.4	
Small business	$ 62.4	
LV residential	$ 62.4	$69.3

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 RCP 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 17B-16 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 17B-17 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 17B-16: 2020-25 revenue cost allocation across network elements and to tariff classes

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

Table 17B-17: 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]	9.7	31.5	175.9	140.4	401.9	759.4
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]	**27.1**	**48.9**	**257.4**	**195.4**	**560.7**	**1,089.4**

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 17B-18: 2020-25 revenue cost allocation to tariff classes (% by tariff class)

Allocation of forecast 2020-25 % 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 $759.4 million is 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.

17.10.4 Cost allocation

The demand applied in the cost 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. Residential customer's investment in solar systems has shifted the co-incident peak from the time of business peak to that of residential peak. If we used co-incident peak, that would result in residential customers paying more post-investment in solar with business customers paying less.

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.

The percentage of cost allocation by tariff class for the 2020/21 forecast are show in Table 17B-16, with the cost allocation outcomes for 2020/21 outlined in Table 17B-17 and Table 17B-18.

17.10.5 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[28] charges. This is in line with the recommendations of the Electricity Advisory Panel, a group established in 2016 to 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 17B-19, 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 17B-19: Residual distribution cost recovery 2020/21

Tariff element	Major business	HV business	Large LV business	Small Business	Residential
Peak Demand	17%	20%	21%	1%	0%
Anytime Demand	73%	30%	21%	3%	0%
Fixed Charges	0%	10%	8%	12%	31%
Usage Charges	11%	40%	50%	84%[1]	69%

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.

Note 2. Residential prosumer recovers 40% of the usage via the summer demand charge, ie peak demand 28%, fixed charges 31% and usage charges 41%.

17.10.6 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 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 17B-20 below shows the indicative prices for 2020/21 to recover $80M in PV-FiT recovery.

Table 17B-20: FiT cost recovery

Tariff Element	Major business	HV business	Large LV business	Small Business	Small Business/ unmetered	Residential	Controlled Load
Fixed Charges $pa	-	-	-	$15.00	-	$15.00	-
Usage Charges c/kWh	0.08	0.33	0.51	0.68	0.68	1.16	1.16

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

17.10.7 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.

Transmission prices will be reset for the 2023-2028 period (ie from July 2023), and the annual charges to be recovered each year will vary due to:

- Changes in CPI and past under/over recovery
- Transmission Incentive Scheme Payments
- Proceeds from settlement residues from the interconnector and payments to/from other networks interstate
- Pass-throughs - There are three contingent projects currently under review:
  - Fly wheels (main grid strength); revenue increase in 2020/21 by $5m, 2021/22 by $11m and 2022/23 by $16m.
  - Eyre Peninsula upgrade; revenue impacts have not been determined yet.
  - Interconnection with NSW; revenue impacts have not been determined yet.

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

Clause 6.18.5(h) of the Rules 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 17.4.

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

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 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.
Distributor, 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.

Abbreviation	Definition or description
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 peak demand is referenced. See also PF for the relationship between power demand quantities.
kW, MW	Kilowatts 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-workday, 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
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) = √ [Real Power (kW)2 + 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

Abbreviation	Definition or description
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 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.
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 workday, Monday through to Friday excluding public holidays.