DRAFT DECISION

SA Power Networks
Distribution Determination
2020 to 2025

Attachment 18
Tariff structure statement

October 2019

AUSTRALIAN ENERGY REGULATOR

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Note

This attachment forms part of the AER's draft decision on the distribution determination that will apply to SA Power Networks for the 2020–2025 regulatory control period. It should be read with all other parts of the draft decision.

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

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 incentive scheme

Attachment 12 – Classification of services

Attachment 13 – Control mechanisms

Attachment 14 – Pass through events

Attachment 15 – Alternative control services

Attachment 16 – Negotiated services framework and criteria

Attachment 17 – Connection policy

Attachment 18 – Tariff structure statement

Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CPI	consumer price index
distributor	distribution network service provider
DUoS	distribution use of system
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER or the rules	national electricity rules
NSP	network service provider
opex	operating expenditure
RAB	regulatory asset base
RIN	regulatory information notice
repex	replacement expenditure

Glossary of terms

Term	Interpretation
Anytime demand tariff	A tariff incorporating a demand charge where the demand charge measures the customer's maximum demand at any time (i.e. not limited to within a peak charging window).
Apparent power	See kVA
CoAG Energy Council	The Council of Australian Governments Energy Council, the policymaking council for the electricity industry, comprised of federal and state (jurisdictional) governments.
Consumption tariff	A tariff that incorporates only a fixed charge and usage charge and where the usage charge is based on energy consumed (measured in kWh) during a billing cycle, and where the usage charge does not change based on when consumption occurs. Examples of consumption tariffs are flat tariffs, inclining block tariffs and declining block tariffs.
Cost reflective tariff	Consistent with the distribution pricing principles in the NER, a cost reflective distribution network tariff is a tariff that a distributor charges in respect of its provision of direct control services to a retail customer that reflects the distributor's efficient costs of providing those services to the retail customer. These efficient costs reflect the long run marginal cost of providing the service and contribute to the efficient recovery of residual costs.
Declining block tariff	A tariff in which the per unit price of energy decreases in steps as energy consumption increases past set thresholds.
Demand charge	A tariff component based on the maximum amount of electricity consumed by the customer (measured in kW, kVA or kVAr) over a designated time-period which may be reset after a specific period (e.g. at the end of a month or billing cycle). A demand charge could be incorporated into either an anytime demand tariff or a time-of-use demand tariff.
Demand tariff	A tariff that incorporates a demand charge component.
Fixed charge	A tariff component based on a fixed dollar amount per day that customers must pay to be connected to the network.
Flat tariff	A tariff based on a per unit usage charge (measured in kWh) that does not change regardless of how much electricity is consumed or when consumption occurs.
Flat usage charge	A per unit usage charge that does not change regardless of how much electricity is consumed or when consumption occurs.
Inclining block tariff	A tariff in which the per unit price of energy increases in steps as energy consumption increases past set thresholds.
Interval, smart and advanced meters	Used to refer to meters capable of measuring electricity usage in specific time intervals and enabling tariffs that can vary by time of day.
kVA	Also called apparent power. A kilovolt-ampere (kVA) is 1000 volt-amperes. Apparent power is a measure of the current and voltage and will differ from real power when the current and voltage are not in phase.
kW	Also called real power. A kilowatt (kW) is 1000 watts. Electrical power is measured in watts (W). In a unity power system the wattage is equal to the voltage times the current.
kWh	A kilowatt hour is a unit of energy equivalent to one kilowatt (1 kW) of power used for one hour.
LRMC	Long Run Marginal Cost. Defined in the National Electricity Rules as follows:

Term	Interpretation
	"the cost of an incremental change in demand for direct control services provided by a Distribution Network Service Provider over a period of time in which all factors of production required to provide those direct control services can be varied".
Minimum demand charge	Where a customer is charged for a minimum level of demand during the billing period, irrespective of whether their actual demand reaches that level.
NEO	The National Electricity Objective, defined in the National Electricity Law as follows: *"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—* *(a) price, quality, safety, reliability and security of supply of electricity; and* *(b) the reliability, safety and security of the national electricity system".*
Power factor	The power factor is the ratio of real power to apparent power (kW divided by kVA).
Tariff	The network tariff that is charged to the customer's retailer (or in limited circumstances, charged directly to large customers) for use of an electricity network. A single tariff may comprise one or more separate charges, or components.
Tariff charging parameter	The manner in which a tariff component, or charge, is determined (e.g. a fixed charge is a fixed dollar amount per day).
Tariff class	A class of retail customers for one or more direct control services who are subject to a particular tariff or particular tariffs.
Tariff structure	Tariff structure is the shape, form or design of a tariff, including its different components (charges) and how they may interact.
Time-of-use demand tariff (ToU demand tariff)	A tariff incorporating a demand charge where the demand charge measures the customer's maximum demand during a peak charging window. A ToU demand charge might also include an off-peak demand change or minimum demand charge, and may include flat, block or time-of-use energy usage charges.
Time-of-use energy tariff (ToU energy tariff)	A tariff incorporating usage charges with varying levels applicable at different times of the day or week. A ToU energy tariff will have defined charging windows in which these different usage charges apply. These charging windows might be labelled the 'peak' window, 'shoulder' window, and 'off-peak' window.
Usage charge	A tariff component based on energy consumed (measured in kWh). Usage charges may be flat, inclining with consumption, declining with consumption, variable depending on the time at which consumption occurs, or some combination of these.

18 Tariff structure statement

This attachment sets out our draft decision on SA Power Networks' tariff structure statement to apply for the 2020–25 regulatory control period.

A tariff structure statement applies to a distributor's tariffs for the duration of the regulatory control period. It should describe a distributor's tariff classes and structures, the distributor's policies and procedures for assigning customers to tariffs, the charging parameters for each tariff, and a description of the distributor's approach to setting tariffs in pricing proposals. It is accompanied by an indicative pricing schedule.[1] A tariff structure statement provides consumers and retailers with greater certainty and transparency in relation to how and when network prices will change.

This allows consumers to make more informed decisions about their energy use and result in better outcomes for both individual consumers and the overall electricity system. In particular, the tariff structure statement informs customer choices by:

- providing better price signals—tariffs which reflect what it costs to use electricity at different times allow customers to make informed decisions to better manage their bills
- transitioning tariffs to greater cost reflectivity—with the requirement that distributors explicitly consider the impacts of tariff changes on customers, by engaging with customers, customer representatives and retailers in developing network tariff proposals
- managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for a set period of time.

Background to this decision

This is SA Power Networks' second tariff structure statement and applies to the 2020–25 regulatory control period. Under the National Electricity Rules' (NER), SA Power Networks needs to ensure the AER is “reasonably satisfied” that its proposal complies with the distribution pricing principles and other applicable requirements.[2] The pricing principles require distributors to transition to cost reflective tariffs and, in doing so, to account for impacts on consumers.

In our final decision on SA Power Networks' first tariff structure statement, which applies from 1 July 2017 to 30 June 2020, we established the focus of tariff reform is to expose retailers to the costs of network congestion to incentivise them to manage this exposure.[3] However, we noted that transitioning to cost reflective pricing will take more than one

[1] NER, cl. 6.18.1A(a).

[2] NER, cl. 6.12.3(k).

[3] AER, *Final Decision: Tariff structure statements: SA Power Networks*, February 2017, p. 7.

regulatory control period.[4] We also set an expectation that subsequent tariff structure statements should propose additional reforms in order to comply with the NER.[5]

In addition, we stated there were elements of SA Power Networks' tariff structure statement proposal which comply with the distribution pricing principles at that time but which would benefit from further consideration in future. [6] Specifically, to provide guidance to SA Power Networks for its 2020–25 tariff structure statements, we identified that SA Power Networks should:

- increase the integration between network pricing, network planning and demand management strategies[7]
- consider interactions between cost reflective tariffs and emerging technologies, such as batteries and electric vehicles[8]
- develop assignment policies to increase the speed of transition to cost reflective tariffs[9]
- revise charging windows to more closely reflect the times of network congestion[10]
- refine its method for estimating long run marginal cost (LRMC), including the inclusion of replacement capex within marginal cost estimates[11]
- reconsider the use of a 30-minute window to measure demand, either monthly maximum (including averaging) or during coincident peaks, to reflecting network costs.[12]

18.1 SA Power Networks' proposal

SA Power Networks' tariff structure statement proposed for the 2020–25 regulatory control period seeks to continue the pricing reform commenced as part of the 2017–20 tariff structure statement by:

- assigning all new customer connections, and reassigning customers who upgrade their connections or who receive a smart meter to replace their ageing interval meter, to cost reflective tariffs[13]
- reassigning all current residential customers with a Type 4 or Type 5 (interval) meter to the residential time of use (ToU) tariff and off-peak controlled load (OPCL) customers with Type 4 meters to the OPCL ToU tariff[14]

[4] AER, *Final Decision: Tariff structure statements: SA Power Networks*, February 2017, p. 8.
[5] AER, *Final Decision: Tariff structure statements: SA Power Networks*, February 2017, p. 45.
[6] AER, *Final Decision: Tariff structure statements: SA Power Networks*, February 2017, pp. 47, 60 & 67.
[7] AER, *Final Decision: Tariff structure statements: SA Power Networks*, February 2017, p. 26.
[8] AER, *Final Decision: Tariff structure statements: SA Power Networks*, February 2017, p. 49.
[9] AER, *Final Decision: Tariff structure statements: SA Power Networks*, February 2017, p. 47.
[10] AER, *Final Decision: Tariff structure statements: SA Power Networks*, February 2017, p. 67.
[11] AER, *Final Decision: Tariff structure statements: SA Power Networks*, February 2017, p. 60.
[12] AER, *Final Decision: Tariff structure statements: SA Power Networks*, February 2017, p. 74.
[13] SA Power Networks, *2020-25 Tariff Structure Statement*, January 2019, p. 11.
[14] SA Power Networks, *2020-25 Tariff Structure Statement*, January 2019, p. 54.

- refining the portfolio of cost reflective tariffs, such as aligning the OPCL tariffs with the residential ToU tariff to provide clear, consistent signals[15] and providing businesses a choice between actual and agreed demand measurements to offer flexibility[16]
- introducing a 'solar sponge' period for time of use tariffs and changing OPCL arrangements to encourage consumption when solar generation (and exports) is high[17]
- introducing locational (CBD and non-CBD) tariffs for business customers to reflect the different peaks that occur in each area as a result of the absence of residential demand and PV generation in Adelaide's CBD compared to the rest of South Australia.[18]

SA Power Networks also proposed to:

- increase its fixed charges to recover 25 per cent overall costs by 2025, limiting annual increases to $10 or less to mitigate the impact on customers[19]
- complete the transition from inclining block tariff to single rate offer for legacy customers with Type 6 (accumulation) meters.[20]

18.2 Draft decision

Our draft decision is to accept SA Power Networks' tariff structure statement as we consider it complies with the distribution pricing principles and contributes to the achievement of the network pricing objective.[21]

We consider the SA Power Networks' proposal provides a strategy to advance the development of cost reflective pricing of distribution services, refined to reflect stakeholder feedback received through its consumer engagement.

An example of this is SA Power Networks' proposal to change the residential cost reflective tariff from a demand structure to a default Time of Use (ToU) structure:

- This proposal was in response to consumers requesting more simplicity and SA Power Networks noting minimal engagement with the demand tariff previously offered. SA Power Networks also priced the ToU components with reference to the single rate tariff for ease of comparison.
- In establishing the structure of the ToU tariff, SA Power Networks noted periods of excess solar generation in the low voltage networks are a major cost driver for current and future costs. Accordingly it introduced a discounted 'solar sponge' period from 10:00 to 15:00 to incentivise consumers to shift consumption to this period.
- Consumers requested SA Power Networks consider softening the peak signal to lessen the impact of mandatory reassignment to ToU tariffs for those with the required interval

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15 SA Power Networks, *2020-25 Tariff Structure Statement*, January 2019, p. 42.

16 SA Power Networks, *2020-25 Tariff Structure Statement*, January 2019, p. 45.

17 SA Power Networks, *2020-25 Tariff Structure Statement*, January 2019, p. 32.

18 SA Power Networks, *2020-25 Tariff Structure Statement*, January 2019, p. 46.

19 SA Power Networks, *2020-25 Tariff Structure Statement*, January 2019, p. 37.

20 SA Power Networks, *2020-25 Tariff Structure Statement*, January 2019, p. 13.

21 NER, cl. 6.18.5 (a).

meters (Type 4 and 5) given the coincident peak does not appear to be driving capex at this stage. In response, SA Power Networks' residential ToU tariff has two peak periods (06:00 to 10:00 and 15:00 to 01:00) with prices only marginally (25 per cent) above the flat rate tariff.

- To address the AER's guidance to use these tariffs to provide retailers with clear signals for investment in, and use of, the network, SA Power Networks aligned its secondary off-peak controlled load (OPCL) tariffs with the ToU structures and timings.
- In response to the rapid rise of solar PV, expected growth of batteries and potential entrance of electric vehicles, SA Power Networks also introduced an optional prosumer demand tariff to help those willing to respond to network prices to benefit from lower bills.

However, for those customers with Type 6 (accumulation) meters SA Power Networks refined its inclining block tariff into a single rate tariff for simplicity. SA Power Networks noted in its proposal these customers can request their retailer to change their meter to a new Type 4 (interval meter) if they wish to access the more innovative tariffs.

We have seen similar things with SA Power Networks' engagement with the business community where a choice is offered between agreed or actual demand tariffs to offer flexibility. At the same time, different charging windows have been established for the central business district (CBD) of Adelaide and the rest of the state to reflect differing peak periods.

We commend SA Power Networks for the consultation it undertook to help develop its tariff structure statement. We also commend the inclusion in its proposal of a table outlining key customer feedback and how it was incorporated into SA Power Networks' proposed tariff structure statement.[22] We consider SA Power Networks used consumer input to shape the manner in which it developed its strategy while maintaining responsibility for its proposal. Additionally, SA Power Networks' proposal included a clear strategy with analysis of the network costs to be reflected in network prices, as well as targeted measures intended to increase cost reflectivity and improve price signals.

There could be value in SA Power Networks revisiting parts of its proposal

While our draft decision is that SA Power Networks' proposal is compliant with the Rules, we consider SA Power Networks may strengthen its proposal further.

SA Power Networks' long run marginal cost (LRMC) methodology could be improved through some modifications and clarifications. SA Power Networks used the average incremental cost approach with 20 years of forecast data as inputs. This approach is commonly used by Australian distributors and we consider it is appropriate. However, we encourage SA Power Networks to consider the following:

- it is important that repex inputs are driven by incremental demand, rather than the condition and age of the assets and that this is clearly communicated

[22] SA Power Networks, *2020-25 Tariff Structure Statement*, January 2019, p. 37-38.

- linking LRMC estimates to forecast repex and augex is important to help stakeholders understand why capex estimates may appear high, particularly when forecasting lower demand
- SA Power Networks used the same estimation method as used for its current tariff structure statement but we encourage distributors to consider whether improvements in the methodology can be found for each subsequent round of tariff structure statement proposals.

We note SA Power Networks advised the AER it is currently reviewing its LRMC methodology. We will consider to what extent SA Power Networks' revisions address these points in the context of our final decision.

Additionally, while SA Power Networks indicated how it plans to allocate costs between tariff classes and structures for foreseeable costs, 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, it would be helpful for consumers to have guidance on how SA Power Networks plans to address these changes in revenue recovery through its annual pricing proposals.

Finally, we have encouraged distributors to consider using a targeted two-document tariff structure statement in recent determinations, similar to that of Endeavour Energy.[23] The first document of this structure is limited to the content that will bind the distributor over the regulatory control period. The second document explains the distributor's reasons for adopting those binding positions.

We recognise SA Power Networks has made efforts to explain the manner in which the Rules have shaped its proposal, including a Compliance Statement in appendix B.[24] However, we consider the two-document structure provides a more readable document, improving clarity for retailers, customers and regulators alike.

18.3 Assessment approach

This section outlines our approach to assessing tariff structure statements.

There are two sets of requirements for tariff structure statements. First, the NER set out a number of elements that an approved tariff structure statement must contain.[25] Second, a tariff structure statement must also comply with the distribution pricing principles.[26]

What must a tariff structure statement contain?

The NER requires a tariff structure statement to include:[27]

- the tariff classes into which retail customers for direct control services will be divided

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23 Endeavour Energy, *2019-24 Tariff Structure Statement and Explanatory Statement*, April 2018.

24 SA Power Networks, *2020-25 Tariff Structure Statement*, January 2019, p. 72.

25 NER, cl. 6.18.1A(a).

26 NER, cl. 6.18.1A(b).

27 NER, cl. 6.18.1A(a).

- the policies and procedures the distributor will apply for assigning retail customers to tariffs or reassigning retail customers from one tariff to another
- structures for each proposed tariff
- charging parameters for each proposed tariff
- a description of the approach that the distributor will take in setting each tariff in each pricing proposal.

A distributor's tariff structure statement must be accompanied by an indicative pricing schedule.[28] This guides stakeholder expectations about changes in network charges over the 2020–25 regulatory period.

What must a tariff structure statement comply with?

In developing a tariff structure statement, distributors should ensure their proposals use the distribution principles[29] to contribute to achieving the network pricing objective.[30] But this must be tempered by compliance with the customer impact principles[31] which require the achievement of this objective to be tempered by customers' understanding of, and ability to respond to, the proposed tariffs. The relevant principles may be summarised as:

- for each tariff class, expected revenue to be recovered from customers must be between the stand alone cost of serving those customers and the avoidable cost of not serving those customers.[32]
- each tariff must be based on the long run marginal cost of serving those customers, with the method of calculation and its application determined with regard to the costs and benefits of that method, the costs of meeting demand from those customers at peak network utilisation times, and customer location.[33]
- expected revenue from each tariff must reflect the distributor's efficient costs, permit the distributor to recover revenue consistent with the applicable distribution determination, and minimise distortions to efficient price signals.[34]
- distributors must consider the impact on customers of tariff changes and may depart from efficient tariffs, if reasonably necessary having regard to:[35]
    - the desirability for efficient tariffs and the need for a reasonable transition period (that may extend over one or more regulatory periods)
    - the extent of customer choice of tariffs
    - the extent to which customers can mitigate tariff impacts by their consumption

[28] NER, cl. 6.8.2(d1).
[29] NER, cl. 6.18.5(b).
[30] NER, cl. 6.18.5(a).
[31] NER, cl. 6.18.5(h).
[32] NER, cl. 6.18.5(e).
[33] NER, cl. 6.18.5(f).
[34] NER, cl. 6.18.5(g).
[35] NER, cl. 6.18.5(h).

- tariff structures must be reasonably capable of being understood by retail customers assigned to that tariff.[36]
- tariffs must otherwise comply with the NER and all applicable regulatory requirements.[37]

The tariff structure statement must comply with the distribution pricing principles in a manner that will contribute to the achievement of the *network pricing objective:*[38]

> *The network pricing objective is that the tariffs that a DNSP charges in respect of its provision of direct control services should reflect the DNSP's efficient costs of providing those services to the retail customer.*[39]

Role of the Tariff Structure Statement

In 2014, the AEMC made important changes to the distribution pricing rules, including the process through which network tariffs are determined.

This included splitting the network pricing process into two stages.

Table 18.1 Two stage network pricing process

	Requirements
First stage	Distributors develop a proposed tariff structure statement to apply over the five year regulatory control period. The tariff structure statement outlines the distributor's tariff classes, tariff structures, tariff assignment policy and approach to setting tariff levels in accordance with the distribution pricing principles. The tariff structure statement is accompanied by an indicative pricing schedule that sets out expected price levels over the five year regulatory proposal. This document is submitted to the AER for assessment against the distribution pricing principles in conjunction with the distributor's five year regulatory proposal. The AER then approves the tariff structure statement if it meets the distribution pricing principles and other National Electricity Rules requirements.
Second stage	Distributors develop and submit their annual pricing proposals to the AER. The annual pricing proposals essentially apply pricing levels to each of the tariff structures outlined in the approved tariff structure statement. Distributor's proposed pricing levels must be consistent with the indicative pricing schedule, or the distributor must explain why its proposed price levels differ from the indicative pricing schedule. The AER's assessment of the distributor's pricing proposal is a compliance check against the approved tariff structure statement and the control mechanism specified in the AER's regulatory determination.

Splitting the network pricing process into two stages was a significant change from the previous arrangements. The AEMC considered this would promote several objectives and allow for:

- requirements that would facilitate meaningful consultation and dialogue between distributors, the AER, retailers and consumers

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36 NER, cl. 6.18.5(i).

37 NER, cl. 6.18.5(j); this requirement includes jurisdictional requirements.

38 NER, cl. 6.18.5(d)

39 NER, cl. 6.18.5(a)

- increased certainty with respect to changes in network tariff structures and more timely notification of approved changes to network tariff pricing levels
- more opportunity for retailers and consumers to inform and educate themselves about how network tariffs will affect them and how they should respond to the pricing signals
- the AER to have appropriate timeframes and capacity to assess the compliance of the distributors' proposed network tariffs against the distribution pricing principles and other requirements, and
- distributors to maintain ownership of network tariffs and to adjust the pricing levels of their tariffs to recover allowed revenues.[40]

What happens after a tariff structure is approved?

Once approved, a tariff structure statement will remain in effect for the relevant regulatory control period. The distributor must comply with the approved tariff structure statement and be consistent with the indicative pricing schedule[41] when setting prices annually for direct control services.[42]

We will separately assess the distributor's annual tariff proposals for the coming 12 months. Our assessment of annual tariff proposals will be consistent with the requirements of the relevant approved tariff structure statement.

An approved tariff structure statement may only be amended within a regulatory control period with our approval,[43] unless it involves introducing a 'sub-threshold tariff' which provides more flexibility under certain conditions.[44] We will approve an amendment if the distributor demonstrates that an event has occurred that was beyond its control and which it could not have foreseen, and that the occurrence of the event means that the amended tariff structure statement materially better complies with the distribution pricing principles.[45]

18.4 Reasons for draft decision

Our draft decision is to approve SA Power Networks' tariff structure statement as compliant with the distribution pricing principles, including contributing to the achievement of the network pricing objective.[46] We consider SA Power Networks engaged consumers and aligned its tariff structure statement with the conditions and context of its network, namely the negligible capacity constraints and significant embedded solar PV generation.

While we believe the tariff structure statement demonstrates compliance with the distribution pricing principles, including the customer impact principles, we consider there is still room for

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40 Australian Energy Market Commission, *Rule Determination - National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, November 2014, p. 64.

41 Distributors must explain any material departure from the indicative pricing schedule in their annual pricing proposals. NER, cl. 6.18.2(b)(7A).

42 NER, cl. 6.18.1A(c).

43 NER, cl. 6.18.1B.

44 NER, cl. 6.18.1C.

45 NER, cl. 6.18.1B(d).

46 NER, cl. 6.18.5(d)

some further changes which will improve the statement. For example, while SA Power Networks outlined how it plans to allocate expected changes in each year across tariff classes and components, it could provide more guidance on how it will manage unexpected changes (such as potential under recovery of revenue) in the 2020–25 regulatory control period.

The section below sets out:

- the reasoning for our decision for each customer group
- provides our initial views on SA Power Networks' estimate of long run marginal cost
- assesses the completeness and compliance of the tariff structure statements with the requirements in the NER.

We have also included a series of appendices which support these reasons.

18.4.1 Residential and small business tariffs

We are satisfied that the following aspects of SA Power Networks' proposal for residential and small business customers contribute to the achievement of compliance with the distribution pricing principles:

- the tariffs have been structured to reflect the efficient costs of providing services
- default tariff structures have been simplified to support consumers' understanding
- muted peak signals reflect the absence of significant network constraints
- evidenced strategy to ensure no cross-subsidy and enable more efficient cost recovery
- assignment policies to promote the uptake of cost reflective tariffs.

Tariff design, levels and charging windows

We support responding to consumer requests for simplicity

SA Power Networks proposed to move away from the opt-in residential monthly demand tariff introduced in its first tariff structure statement (2017-20) to a default time of use tariff for residential consumers with appropriate metering (Type 4 and 5 meters). This change in approach was attributed by SA Power Networks to a request for greater simplicity from consumers and retailers.

As above, we consider both demand and time of use tariff structures can be cost reflective. However, to comply with the customer impact principles,[47] SA Power Networks must demonstrate its regard for the capability of consumers to understand the tariff and mitigate the impact of changes in their network tariff. We consider SA Power Networks' decision to change to a simpler tariff structure, and the proposed implementation of this structure, complies with this requirement. Particularly when supported by impact analysis to explore

[47] Frequently used to refer to the pricing principles outlines in cll. 6.18.5(h) and 6.18.5(i) of the NER.

the potential impact on the network costs to be packaged by retailers for consumers within each tariff class.[48]

SA Power Networks proposed a similar approach for small businesses connected to the low voltage network. These customers will also have a default time of use tariff (albeit with a different structure as discussed below) for customers with the enabling infrastructure (Type 4 and 5 meters).

SA Power Networks also negotiated with customers to increase the fixed charge by $10 a year for residential customers and $20 a year for small business customers. Within each class customers pay the same fixed charge regardless of the tariff they are on. This will increase the proportion of revenue recovered from fixed charges. However by the end of the regulatory period revenue recovery from fixed charges on these customers will be around 25 per cent, well below the cap of one third of revenue customers were comfortable with.[49]

In structuring their tariffs towards this approach, SA Power Networks has effectively focused long run marginal cost (LRMC) signals at the demand component while the time of use peak and fixed charges are used to recover the residual costs. As discussed later, we consider this to be an appropriate approach given the current low rates of utilisation and absence of significant periods of constraint in SA Power Networks' network.

While offering flat rate for Type 6 (accumulation) meters

SA Power Networks also proposed to move from a two part inclining block tariff to a simple single rate tariff for residential customers whose metering infrastructure does not support more cost reflective tariffs (i.e. Type 6 accumulation meters).

As outlined in recent decisions, we consider flat energy tariffs are generally the most suitable for those with accumulation meters.[50] This is because:

- the cost of supplying an additional unit of electricity is the same regardless of the quantity purchased by a single residential customer
- they are easy for consumers to understand.

Therefore we consider grandfathering flat tariffs, by allowing consumers with accumulation meters to stay on flat tariffs until they receive a new meter or change connection characteristics, is an appropriate strategy for SA Power Networks.

And the choice of a prosumer tariff

SA Power Networks proposed to offer a ‘prosumer tariff’ with a demand tariff applied over summer (November to March) and lower time of use energy rates for those customers willing to engage with more complex price signals through their retailers. We think offering consumers the ability to benefit from lower prices by shifting or reducing their consumption during peak periods offers benefits to all consumers.

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48 SA Power Networks, *2020-25 Tariff Structure Statement*, Appendix D, January 2019, p. 87.

49 SA Power Networks, *2020-25 Tariff Structure Statement*, Appendix D, January 2019, p. 38.

50 See for example AER, *Final Decision: Tariff structure statements: Essential Energy*, November 2018, p. 15.

We support this being offered on a voluntary basis as consumers, their retailers, and other service providers build their capacity to understand and mitigate the impact of more cost reflective network tariffs. It is encouraging to see that SA Power Networks offered this tariff on a trial basis during the 2019–20 annual pricing proposal to enable consumers to explore interactions between their consumption behaviour and this alternative structure in advance of the coming regulatory period.

We note one submission raised a concern that prosumers might prefer to remain on the time of use tariff as it is clearer and simpler.[51] However, we do not think this is a major concern as the 'prosumer' tariff is offered on an opt-in basis and consumers should be able to choose the tariff offering that best suits them. Also, offering consumers a choice is noted as a mitigating factor under the customer impact principles with regard to the extent to which a distribution business may need to deviate from the pursuit of cost reflective network tariffs.[52]

We support refining and aligning different offers

SA Power Networks proposed to align the off-peak controlled load (OPCL) tariffs with the primary retail tariff offerings. Customers with Type 4 meters will be offered the peak, off-peak and solar sponge charging windows and prices offered under the residential time of use tariff. However, customers with Type 5 and 6 meters will not be as closely aligned. This is because their meters require time periods to be manually set rather than remotely managed by the retailer and metering coordinator. These customers will have OPCL periods from 10:00 to 15:00 and 23:00 to 07:00 and the off-peak price will be applied to consumption during these periods.

We consider SA Power Networks' alignment of OPCL tariffs with primary retail tariffs contributes to addressing the consumer preference for simplicity. At the same time SA Power Networks' approach provides retailers with clear signals of the cost associated with consumers' use of the network.

SA Power Networks proposed to refine small business tariffs to provide clearer, simpler structures. Small businesses have been moved from the demand tariff structures in the first tariff structure statement to a time of use tariff structure with an optional additional anytime demand charge (compulsory for businesses over 70kVA). The anytime consumption and two rate tariffs for consumers with Type 6 accumulation meters have been continued. The charging windows for the two rate tariff have been aligned with the time of use structure for those with interval meters (Types 4 and 5). The unmetered tariff, including streetlights, has been set around the level of the off-peak rate for small businesses.

Charging windows should be targeted at network constraints

SA Power Networks proposed to structure the residential time of use tariff with:

- an off-peak period between 01:00 and 06:00

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[51] John Herbst, *Submission on SA POWER NETWORKS Regulatory Proposal 2020-25,* 23 May 2019.

[52] NER, cl. 6.18.5(h)(2)

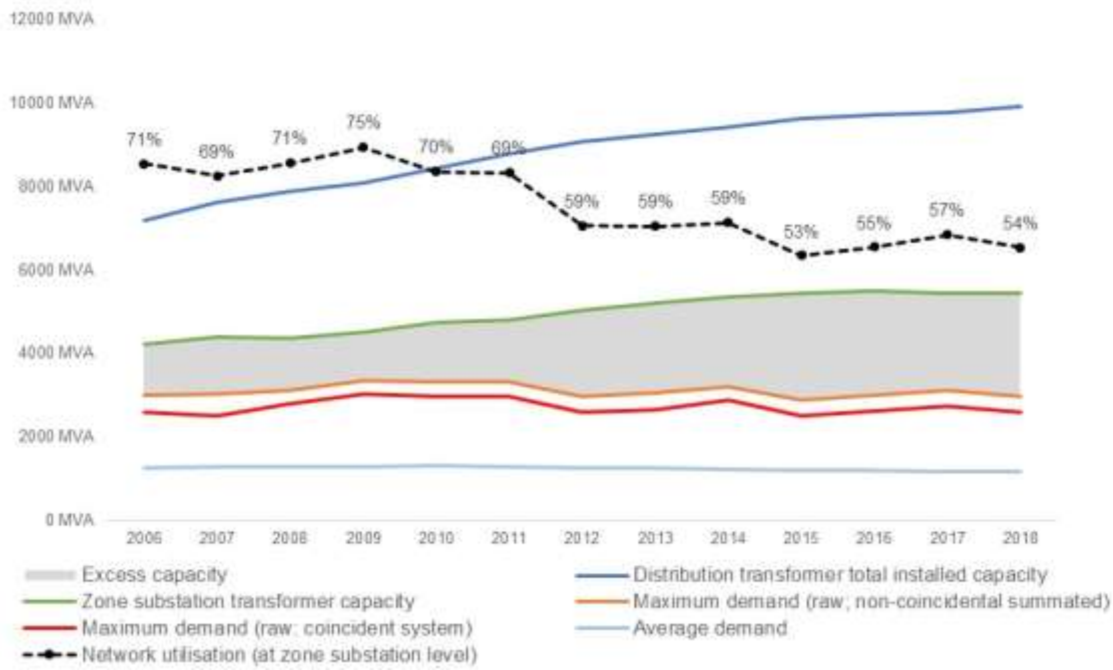
- a heavily discounted solar sponge between 10:00 and 15:00 to encourage consumption while rooftop PV is generating
- the rest of the day priced at peak period rates.

SA Power Networks proposed a less targeted peak period charging window than we would normally consider appropriate. However, SA Power Networks negotiated this lower, longer peak period with consumers to reflect the absence of significant constraints while building understanding of, and capacity to respond to, time of use pricing structures.

In contrast to SA Power Networks' time of use tariff, the demand component of SA Power Networks' prosumer tariff is more targeted with the charging window focused from 17:00 to 21:00.

The absence of significant capacity constraints is consistent with data on network utilisation provided by SA Power Networks in its annual RIN data. The graph below illustrates capacity and use (demand) of the network, as well as utilisation at the zone substation level. Utilisation has declined steadily since 2009 with maximum demand only totalling 54 per cent of available zone substation transformer capacity by 2018. While aggregates can hide diversity in conditions at each zone substation, SA Power Networks' distribution annual planning report for 2018–19 to 2022–23 does not suggest this is the case in the near term.

Figure 18.1 SA Power Networks' network utilisation



Source: AER analysis of network RIN data.

The existence of spare capacity is also reflected in SA Power Networks' long run marginal cost estimates being revised marginally lower compared to estimates from its first tariff structure statement in 2017, see Table 18.2 below. This suggests that an incremental change in demand can at least partly be met by spare capacity within the network. For example, the long run marginal cost of an incremental increase in large business demand connected to the HV network has been reduced from $80/kVA per year to $56/kVA per year. Also with SA Power Networks currently reviewing this methodology, there is the potential for these to be reduced further.

Table 18.2 Comparison of SA Power Networks' LRMC estimates between TSS

Tariff class	2017 LRMC estimate ($/kVA p.a.)	2019 LRMC estimate ($/kVA p.a.)
Major business – sub transmission	22	18
Major business – zone substation	57	43
Large HV business	80	56
Large LV business	100	87
Small business	111	107
LV residential	111	107

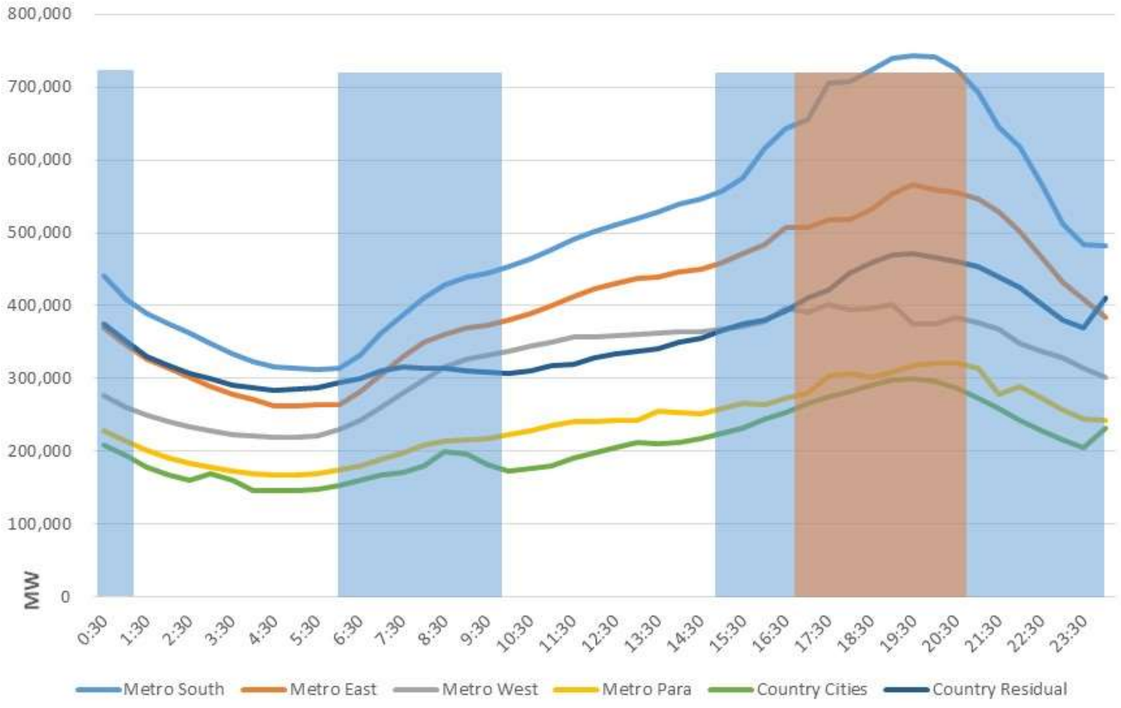
Source: SA Power Networks' Tariff Structure Statements.

We note SA Power Networks also has a State Government imposed obligation to offer the same tariff to all residential and small business customers, regardless of their location.[53] For simplicity, these charging windows are pre-set at the start of the regulatory period and apply to each day of the year. This means the charging windows must be structured to ensure periods of congestion are captured within the peak time of use and peak demand periods. The 'solar sponge' must also be structured to ensure periods of minimum demand are covered.

To inform our understanding of the selected charging windows, SA Power Networks provided the AER with data including minimum and maximum demands. This data is illustrated in the following graphs which respectively show the maximum and minimum demand experienced across six groupings, excluding CBD and major industrial consumers. It can be seen that while the time of use peak period (shaded blue) covers a range of variables for maximum demand, the peak demand tariff (orange) is focused over the network peaks. The 'solar sponge' (shaded yellow) also appears to be well focused over the network minimums across each grouping.

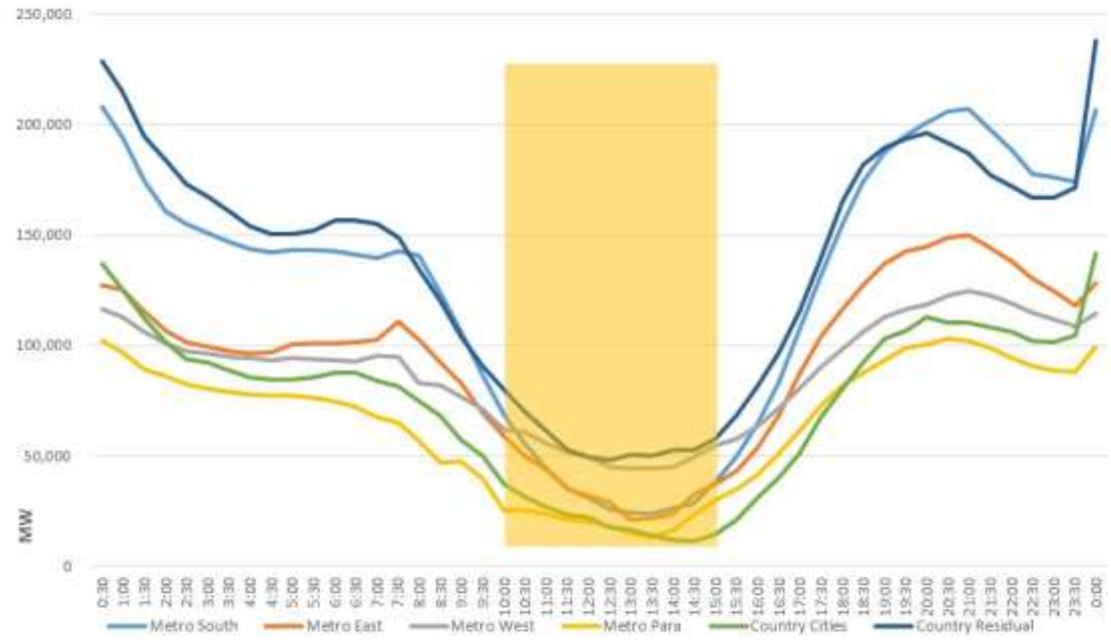
[53] South Australian Treasurer, *Electricity Act 1996* Section 35B Electricity Pricing Order, 11 October 1999. NER, cl. 7.3 (f)-(h).

Figure 18.2 Maximum Demand ex-CBD



Source: Regional demand data provided by SA Power Networks.

Figure 18.3 Minimum Demand ex-CBD



Source: Regional demand data provided by SA Power Networks.

Small business customers have different time of use charging windows with non-work days set as off-peak and work days' shoulder periods set from 07:00 to 17:00 between November and March when the peak charge applies and 07:00 to 21:00 for the rest of the year.

However, the peak component of the time of use tariff is timed to coincide with the residential demand tariff from 17:00 to 21:00 every day between November and March when network constraints are more likely to arise. As with the retail tariffs, we consider this approach to represent a balance between reflecting network costs and managing the impact on customers.

Tariff strategy addresses cross-subsidies and fairness

Under the pricing principles, distribution businesses are required to set their tariffs so that the revenue recovered from each tariff class is between the stand-alone cost of serving that class of consumers and the costs that would be avoided by no longer serving that class of consumers.[54] SA Power Networks provided data to show that the revenue to be collected from all tariff classes sits between their stand alone and avoidable costs. Meeting this condition means tariffs are subsidy free.

However, the Rules do not discuss the issue of revenue allocation between different consumers within the same tariff class. With charges priced per unit of energy consumption consumers pay the same amount for their demand regardless of whether it is spread over time or concentrated in a shorter time period. This is despite the fact that the efficient cost of providing sufficient capacity to meet the consumer’s demand in a shorter period would be higher than when it is spread out over time. Additionally, the total efficient cost of serving a consumer will be affected by whether or not their demand occurs during the coincident network peak when everyone else is demanding more capacity from the network.

SA Power Networks proposed a number of changes to address these considerations and comply with the network pricing objective of setting tariffs to reflect the efficient cost of serving the retail customer. These include offering the prosumer tariff for those customers willing to spread their consumption out and reduce the total efficient cost of meeting demand within their tariff class. By charging a higher rate for consumption around the network peak, SA Power Networks will recover more revenue from consumers whose demand contributes to a requirement for greater network capacity to be available during these periods. The solar sponge allows SA Power Networks to encourage consumption during periods of high rooftop PV generation but also reflect the lower cost of serving demand during that period.

Tariff assignment policy

Grandfathering flat tariffs is appropriate at this stage

SA Power Networks proposed to assign customers with meters that will enable the more cost reflective tariffs, either remotely or manually read interval meters, to the default time of use tariff. During the regulatory period consumers who request an interval meter from their retailer, replace an ageing accumulation (Type 6) meter, change their network connection, or create a new network connection will be assigned to the time of use tariff. Customers with a Type 6 meter will be re-assigned from the two part inclining block tariff structure used during the previous tariff structure statement to a single rate tariff. This effectively grandfathers the single rate tariff.

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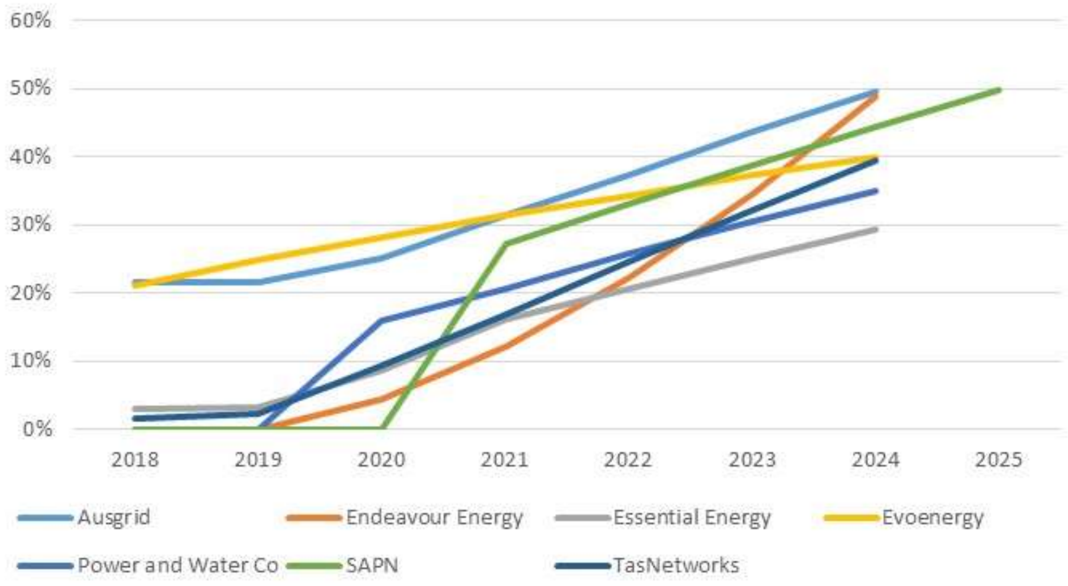
[54] NER, cl. 6.18.5(e).

In reviewing this proposal we considered the requirement for each tariff structure statement to progress tariff reform mitigated only by the customer impact principles.[55] SA Power Networks' proposal increases the pace of reform by substantially increasing the proportion of consumers with cost reflective network tariffs by the end of the regulatory period. This is comparable to recent tariff structure statement decisions in other jurisdictions (see Figure 18.4) and has been informed by customer impact analysis to help consumers understand the implications of the proposal. However this progression of network tariff reform is mitigated by the relatively low peak rate charge set at 125 per cent of the single rate tariff, albeit over a substantial portion of the day, and the heavily discounted off-peak and solar sponge periods. Additionally, submissions received in response to SA Power Networks' proposal appear to indicate general support for this proposal.[56] Therefore we consider this approach of grandfathering single rate tariffs and progressing tariff reform to be appropriate.

Figure 18.4 Assignment of residential customers to cost reflective tariffs



Source: AER analysis of data provided by distribution businesses.

SA Power Networks proposed a similar approach for small business customers with the single rate and two rate tariffs grandfathered for those with Type 6 meters. All other small business customers will be re-assigned to the default time of use tariff with the option to overlay an anytime demand charge for consumers willing to spread their load over a longer period to reduce demand on the network. The one exception is for small business customers with consumption greater than 70 kVA who are seen to dominate demand on local network assets[57] and are required to face the anytime demand tariff. The shoulder and off-peak rates have been discounted for small business customers when the anytime demand component

[55] NER, cl. 6.18.5(h).

[56] For example see submissions from AGL, The Energy Project, John Herbst, Energy Consumers Australia, AER's Consumer Challenge Panel Subpanel 14, SA Minister for Energy and Mining, and GreenSync.

[57] SA Power Networks, *2020-25 Tariff Structure Statement*, January 2019, p. 92.

is overlaid on the time of use tariff. As with residential customers, SA Power Networks' proposed approach has been accompanied by general stakeholder support and customer impact analysis. Therefore we also consider this assignment approach to be appropriate.

We encourage SA Power Networks to keep exploring alternatives on a trial basis

SA Power Networks introduced the residential time of use tariff and off-peak controlled load with time of use rates on a trial basis as part of its annual pricing proposal for 2019–20. SA Power Networks also refined and extended the trial of its locational alternative agreed business demand tariff in the Riverland region for small, medium and large businesses during 2019–20. We consider this to be an appropriate way to explore more innovative cost reflective tariffs, build customer understanding and refine tariff strategies. We encourage SA Power Networks and other businesses to continue to use the flexibility to trial tariffs offered by the Rules.[58]

18.4.2 Medium and large business tariffs

We are satisfied the following aspects of SA Power Networks' proposal for medium and large business customers contribute to compliance with the network pricing objective,[59] distribution pricing principles,[60] and other applicable requirements of the NER:

- offering businesses choice on timing and measurement of demand
- location based charging windows to reflect different times of network congestion
- maintaining assignment to cost reflective tariffs for medium and large businesses.

Tariff design, levels and charging windows

The discussion below focuses on the issues we found that are unique to SA Power Networks' proposal for medium and large businesses. Our findings and discussion above on SA Power Networks' charging windows and approach to setting prices for residential and small business customers is also applicable to medium and large business customers.

We approve offering businesses choice

SA Power Networks proposed to assign all businesses with interval (Type 4 and 5) meters to a tariff with time of use rates for consumption paired with peak demand and anytime demand tariffs. However, SA Power Networks proposed to let each business choose whether their peak demand tariff is based on:

- an agreed value for peak demand between November and March and the cost spread over the year, or

58 NER, cl. 6.18.1C.

59 NER, cl. 6.18.5(a).

60 NER, cl. 6.18.5(d).

- on their actual metered demand during peak periods from November to March and recovered within this period.

Both options will be accompanied by an anytime demand charge. This enables business customers to decide which option best allows them to manage their network costs. We note broad stakeholder support for this approach.[61]

Those medium and large businesses connected to the low voltage network who still have accumulation meters will be offered access to a single or two rate option. Customers utilising transition tariffs will also have the opportunity to continue on these tariffs with the actual demand charge applied from November to March and the anytime demand charge both offered at a discount to the more cost reflective option. SA Power Networks increased the transitional demand tariff by $10/MW in 2019–20 and proposes to do the same again in 2020–21 to narrow the gap between these tariffs.

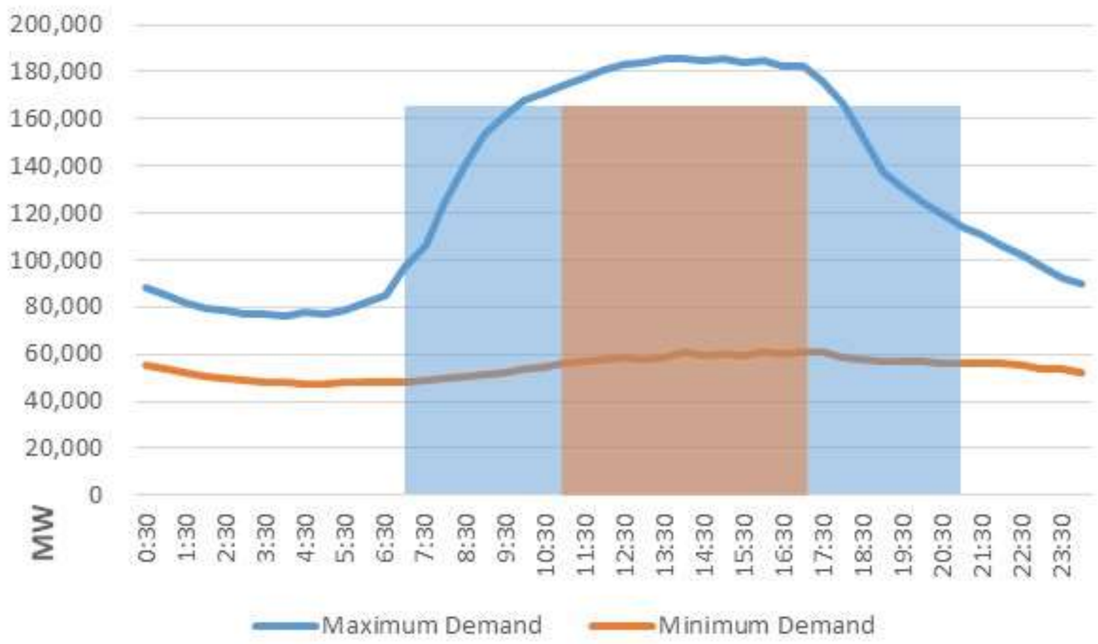
As well as reflecting locational variations in business tariffs

SA Power Networks proposed to differentiate the timing of peak windows for businesses within the central business district (CBD) of Adelaide where there is minimal residential demand and PV generation from businesses located outside of the CBD. This means that while the tariff structures and rates applied to medium and large businesses will be consistently applied across the network, the charging window for peak demand will vary.

This proposal offers an appropriate step forward in ensuring the network prices for consumers accurately reflect the cost of serving those consumers. Comparing Figure 18.2 above with Figure 18.5 below demonstrates the difference in the load profile for the CBD compared to the rest of the network. We believe this justifies establishing an alternative peak period (shaded blue) for the time of use structure and peak window (orange) for the coincident demand charge for businesses in the CBD.

[61] For example, see submissions received from Business SA and the South Australian Wine Industry Association.

Figure 18.5 Maximum Demand CBD



Source: Regional demand data provided by SA Power Networks.

But we seek clarity on individually calculated tariffs

SA Power Networks' proposed tariff structure statement includes individually calculated supply charges for major businesses at the zone substation and sub-transmission level. Given the complexity of connection arrangements and the increased ability of consumers at this level to bypass the distribution network (e.g. by connecting to the transmission network), we are satisfied that it may be more cost reflective for these customers to have an individually calculated supply charge. However, SA Power Networks did not provide information as to how it will calculate the supply charge for these consumers.

We require SA Power Networks to outline its approach to setting the supply charge for these individually calculated components of major business tariffs. This means SA Power Networks will need to detail how it calculated each individually calculated supply charge for the AER as part of the annual pricing process, albeit on a commercial in confidence basis.

Tariff assignment policy

We support SA Power Networks' proposal to maintain assignment of all medium and large businesses to cost reflective tariffs. We consider that medium and large business customers are able to understand their tariffs[62] and manage their usage to mitigate the impact of changes on their retail bills[63] due to the scale of their electricity expenditure. This ensures all

[62] NER, cl 6.18.5(i).

[63] NER, cl 6.18.5(h)(3).

customers capable of facing cost reflective tariffs will do so, facilitating progress towards the network pricing objective.[64]

18.4.3 Long run marginal cost estimate

An important feature of this draft decision is the concept of long run marginal cost. Long run marginal cost is equivalent to the forward looking cost of a distributor providing one more unit of service, measured over a period of time sufficient for all factors of production to be varied.[65] Long run marginal cost could also be described as a distributor's forward looking costs that are responsive to changes in electricity demand.

The NER require network tariffs to be based on long run marginal cost.[66] However, not all of a distributor's costs are forward looking and responsive to changes in electricity demand. If network tariffs only reflected long run marginal cost, a distributor would not recover all its costs. Costs not covered by a distributor's long run marginal costs are called 'residual costs'. The NER require network tariffs to recover residual costs in a way that minimises distortions to the price signals for efficient usage that would result from tariffs reflecting only long run marginal cost.[67]

Below we describe SA Power Networks' approach to estimating long run marginal costs. We then set out our assessment of this approach having regard to the framework in appendix B as the basis of our assessment regarding compliance with the pricing principles.

SA Power Networks estimation method

SA Power Networks used the Average Incremental Cost approach to estimate long run marginal costs over a 20 year forecast period.[68] SA Power Networks included growth-related expenditure and forecast changes in demand over the forecast period as the primary inputs for its calculations.[69]

This is consistent with the method SA Power Networks applied in its first tariff structure statement.[70]

Table 18.3 includes SA Power Networks' long run marginal cost estimates.

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64 NER, cl 6.18.5(d).

65 NER, chapter 10 Glossary defines long run marginal costs as the cost of an incremental change in demand for direct control services provided by a distribution network service provider over a period of time in which all factors of production required to provide those direct control services can be varied.

66 NER, cl. 6.18.5(f).

67 NER, cl. 6.18.5(g)(3).

68 SA Power Networks, *2020–25 Regulatory proposal: Attachment 17: Tariff structure statement*, 31 January 2019, pp. 61–62; SA Power Networks, *2020–25 Regulatory proposal: Attachment 17.1: Long run marginal cost model*, 31 January 2019, LRMC – AIC!.

69 SA Power Networks, *2020–25 Regulatory proposal: Attachment 17: Tariff structure statement*, 31 January 2019, p. 61.

70 SA Power Networks, *2020–25 Regulatory proposal: Attachment 17: Tariff structure statement*, 31 January 2019, pp. 61–62; SA Power Networks, *Revised tariff structure statement 2017–20: Part B*, October 2016, pp. 93–94.

Table 18.3 SA Power Networks' LRMC estimates

Service	LRMC ($/kVA/year)
Sub-transmission	18
HV bus	43
HV net	56
LV bus	87
LV net	107

Source: SA Power Networks, *2020–25 Regulatory proposal: Attachment 17: Tariff structure statement,* 31 January 2019, p. 62; SA Power Networks, *2020–25 Regulatory proposal: Attachment 17.1: Long run marginal cost model*, 31 January 2019, LRMC – AIC!S52:S56.

Assessment of LRMC approach

We are satisfied that SA Power Networks' approach to estimating long run marginal cost contributes to the achievement of compliance with the distribution pricing principles or to the achievement of the network pricing objective. As we discuss below, however, we encourage SA Power Networks to review the types of replacement capital expenditure (repex) included in its LRMC calculations.

Incorporation of repex into LRMC

We are not satisfied SA Power Networks' proposed approach to incorporating repex into its long run marginal cost estimates contributes to compliance with the distribution pricing principles or to the achievement of the network pricing objective. On balance, however, we do not consider this provides grounds for requiring SA Power Networks to amend its method for estimating LRMC in the revised proposal. We encourage SA Power Networks to review the types of replacement capital expenditure (repex) included in its LRMC calculations. We consider SA Power Networks could ensure it included only repex that is consistent with the definition of 'marginal costs'. Such repex would be driven by changes in demand, rather than by the age and condition of assets.

SA Power Networks used the same method to calculate LRMC as its first tariff structure statement,[71] where SA Power Networks stated:[72]

> A detailed review of Repex over the 2015-20 regulatory control period identified some augmentations that provide additional useable network capacity. This is due to the substitution of modern equivalent assets, which frequently have a higher rating than those they replace. The proportions of Repex allocated to system levels are shown in Table 47.

[71] SA Power Networks, *2020–25 Regulatory proposal: Attachment 17: Tariff structure statement*, 31 January 2019, pp. 61.

[72] SA Power Networks, *Revised tariff structure statement 2017–2020: Part B*, October 2016, p. 160; SA Power Networks, *Regulatory proposal 2020–25: Attachment 17.1: Long run marginal cost model*, 31 January 2019.

It appears these projects involve the replacement of assets based on both condition and age and are not associated with 'incremental demand' of network services. While some of these projects may involve a change (specifically, an increase) in network capacity, incremental use of the network is not the driver of this repex.

As we set out in appendix B incremental changes in demand must be the driver for any expenditure to be consistent with the definition of 'marginal cost'. We therefore encourage SA Power Networks to review the repex inputs for its LRMC estimates as part of the revised proposal. Appendix C to this draft decision sets out guiding principles for estimating long run marginal costs. We encourage SA Power Networks to apply these principles in its revised proposal.

Estimation method

We consider that SA Power Networks' method for deriving its long run marginal costs estimates contributes to the achievement of compliance with the distribution pricing principles.

We consider that the Average Incremental Cost approach is fit for purpose at this stage of tariff reform for SA Power Networks.

As we discuss in appendix C, long run marginal costs largely depends on the level of congestion in different locations within a network (as well as temporal factors). However, postage stamp pricing applies across SA Power Networks' network and will continue to apply in the 2020–25 regulatory control period. This limits the extent to which end customers can receive and respond to long run marginal cost signals.

In this context, we consider the limitations of the Average Incremental Cost approach—the perception that the estimates they derive are not the best representations of long run marginal costs—are outweighed by its relatively low cost of implementation.[73] In particular, the Average Incremental Cost approach uses inputs that are readily available as part of a distributor's regulatory proposal: namely, the expenditure and demand forecasts for the 2020–25 regulatory control period.

Forecast horizon

We consider SA Power Networks' proposed forecast horizon contributes to compliance with the distribution pricing principles.

SA Power Networks used a forecast horizon of 20 years to derive its long run marginal cost estimates using the Average Incremental Cost approach. This meets the minimum 10 year forecast horizon that we consider adequately captures the 'long run' (see appendix C).

[73] NER, cl. 6.18.5(f)(1).

18.5 Statement structure and completeness

SA Power Networks must include the following elements within its tariff structure statement:

- the tariff classes into which its customers will be grouped
- the policies and procedures SA Power Networks will apply for assigning customers to tariffs or reassigning customers from one tariff to another (including applicable restrictions)
- the structures for each proposed tariff
- the charging parameters for each proposed tariff
- a description of the approach SA Power Networks will take in setting each tariff in each annual pricing proposal during the regulatory control period.[74]

SA Power Networks must also accompany its proposed tariff structure statement with an indicative pricing schedule which sets out, for each tariff for each regulatory year of the regulatory control period, the indicative price levels determined in accordance with the tariff structure statement.[75]

SA Power Networks' proposed tariff structure statement largely incorporates each of the elements required under the NER. However its proposal was not sufficiently clear regarding its approach to setting tariffs in each annual pricing proposal. This means that SA Power Networks' revised tariff structure statement must be clear about how tariffs will vary from the indicative pricing schedule if there is a variation in revenue or changes to long run marginal cost calculations.

Also, while SA Power Networks provided information and analysis to explain and justify its tariff structure statement, we consider the approach taken by Endeavour Energy to be best practice.[76] So we recommend SA Power Networks consider the “two document approach” with:

- a document outlining only the tariff structure aspects that will be binding on SA Power Networks over the regulatory control period
- a document explaining SA Power Networks' reasons for what it proposed.

This approach improves the clarity for retailers, customers and the AER.[77]

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74 NER, cl. 6.18.1A(a).

75 NER, cl. 6.18.1A(e).

76 Endeavour Energy, *Tariff Structure Statement 1 July 2019 – 30 June 2024,* April 2018.

77 NER, cl. 6.18.5(i).

A Retail/network characteristics and relevance to tariff reform in South Australia

Tariff structure statements cannot be developed in isolation from developments in the broader energy sector. Electricity distributors are required to develop their network tariff strategies against a backdrop of a unique set of environmental conditions. Some of these conditions will constrain the reform of network tariffs whilst other conditions will enable more reform to occur than otherwise the case.

The unique environmental factors relevant to a network pricing context include the following:

- Network design and operating conditions - The nature of the electricity network influences the level and spatial variation in long-run marginal cost (LRMC) of supplying an additional increment of network capacity.
- Penetration of interval metering – Metering functionality is a critical enabler of efficient tariff reform.
- Price elasticity of demand – the extent that consumers respond to network pricing by changing their usage influences the design of efficient tariffs in a number of ways, such as from a residual cost recovery perspective.
- Economic conditions – variations in the business cycle influence the rate of growth in new network connections and investment in new major energy appliances and DER
- Weather conditions – the seasonal nature of peak demand influences the design of efficient tariffs from a peak charging perspective.
- Retailer pricing behaviour – the extent that retailers pass through network pricing signals influences the nature, timing and distribution of the benefits of tariff reform.
- Government intervention – government policy can influence the nature and pace of tariff reform.

The AER must take into account these unique environmental conditions when assessing whether a tariff structure statement proposal complies with the distribution pricing principles set out in Chapter 6 of the NER.

The requirement on distributors to prepare a tariff structure statement arises from a significant process of reform

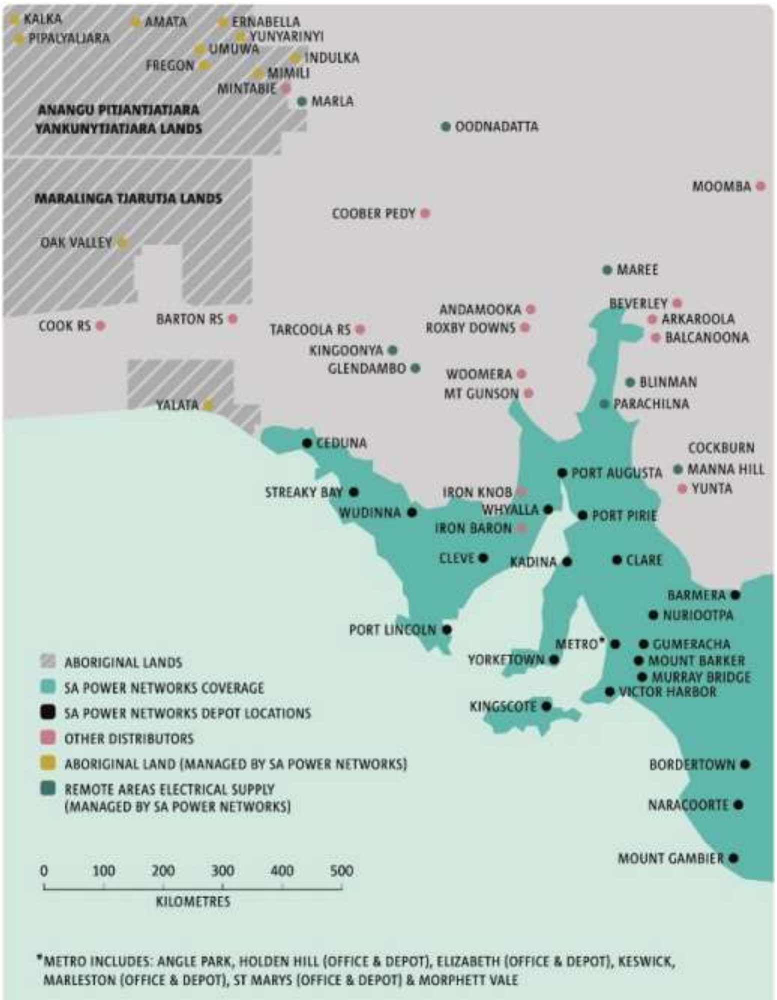
This appendix aims to provide background information and insights into the unique environmental factors faced by each distributor from a network pricing perspective.

A.1 Network design and operating conditions

SA Power Networks provides network services to over 850000 homes and businesses in South Australia through a network covering more than 178000 square kilometres. This network spans 416 zone substations, 647000 poles and 1.1 million meters.

The geographic footprint of the network areas of SA Power Networks is shown in figure A.1 below.

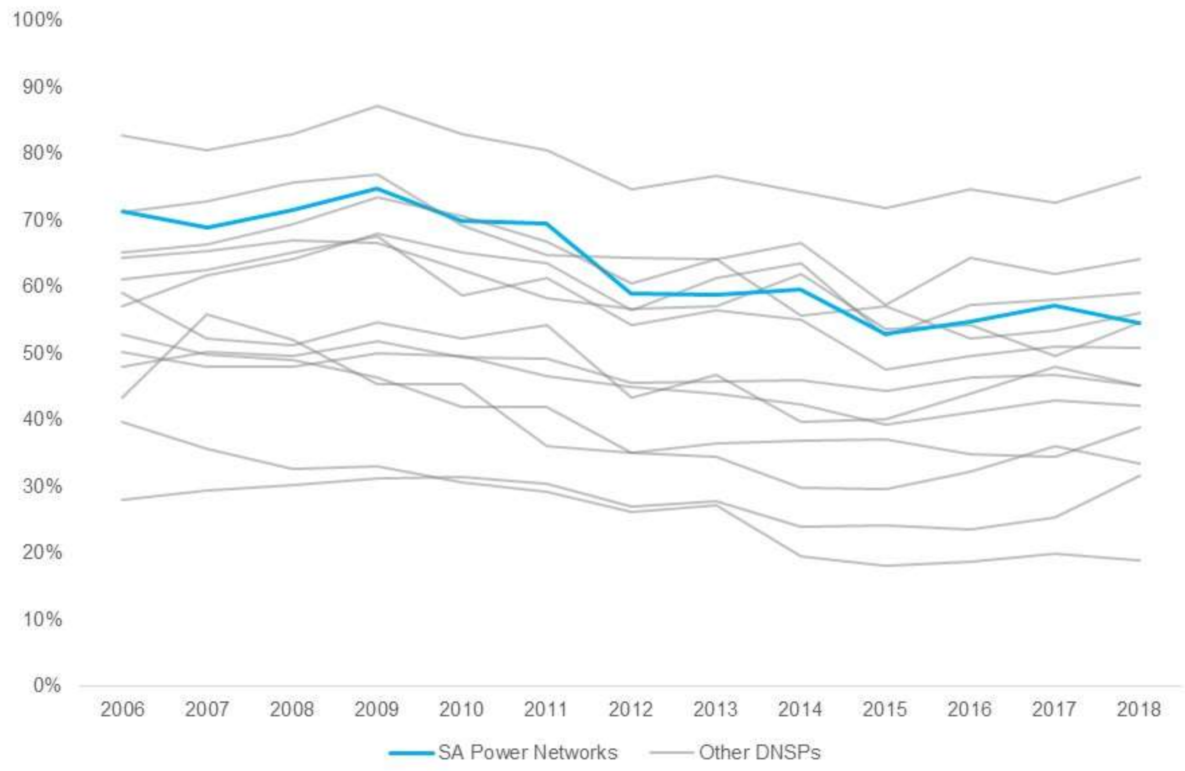
Figure A.1 SA Power Networks' distribution network area



Source: SA Power Networks.

To show how this infrastructure has been used over the last decade or so, figure A. 2 provides a comparison of the historical trend in annual network utilisation for SA Power Networks and the other distributors in the NEM.

Figure A.2 SA Power Networks' network utilisation



Source: AER analysis.

It is clear from the above figure that network capacity utilisation has been declining for SA Power Networks over the past decade. This means SA Power Networks' network is being used less over time which in turn means the cost of maintaining the network is spread over a diminishing base. The reduced utilisation reflects substantial increases in rooftop solar PV reducing demand from the grid. Although stagnation of demand in the aftermath of the global financial crisis and the improved efficiency of household appliances, particularly air-conditioning and lighting, have also reduced use of the network.

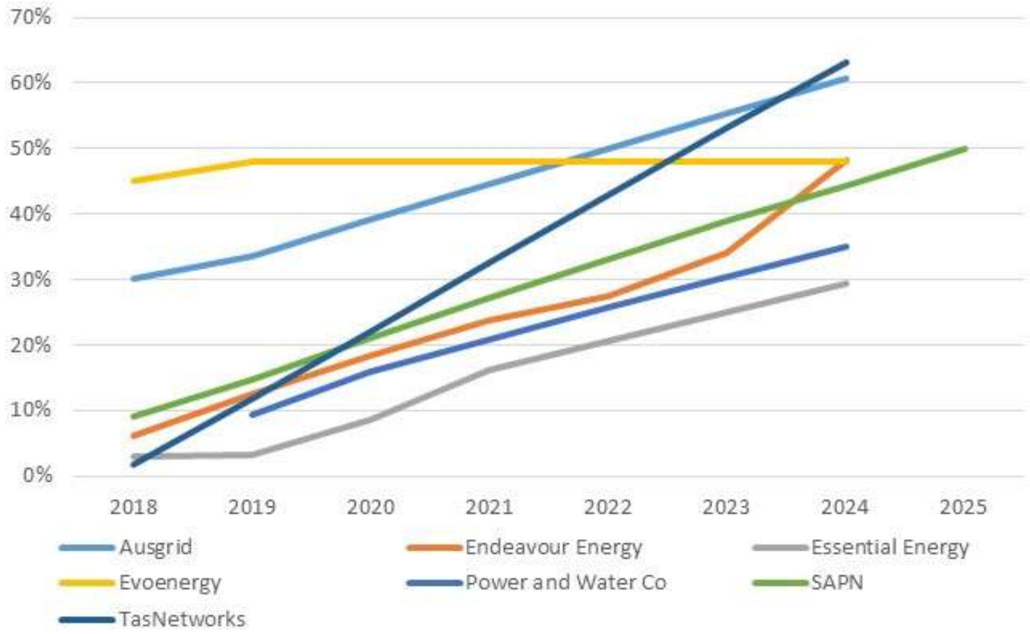
The widespread presence of idle capacity has resulted in peak demand growth no longer being a major driver of future network costs for SA Power Networks which impacts the level and composition of future capital expenditures, as discussed in the section below. This also has implications for SA Power Networks' tariff strategy and contributed to the move towards focusing tariffs towards encouraging demand while rooftop is generating and reduced the focus on peak shaving through price signals.

A.2 Penetration of interval metering and assignment

The penetration of interval metering is a relevant factor to consider from a network pricing perspective because cost reflective network pricing can only be implemented for customers with an interval meter installed in their premise.

Figure A.3 shows that SA Power Networks expects to have a similar penetration of smart metering in the residential customer segment in the medium term to other electricity distributors in the NEM.

Figure A.3 Smart Meter penetration in residential customer segment by electricity distributor



Source: AER analysis.

It is interesting to note that by the end of 2018/19 only 9 per cent of residential customers in SA Power Networks' network had smart meters. This is expected to increase to 50 per cent by the end of the upcoming regulatory period. This expectation reflects the installation of smart metering on a new and replacement basis, as required to comply with the new metering provisions in the NER.[78] It also reflects the impact of the strong uptake of solar PV in SA, with customers upgrading their metering to connect solar PV systems to the electricity network.

A.3 Proposed procedures for tariff assignment and reassignment

The extent that an increase in the penetration of interval metering translates to an increase in the number of customers on more cost reflective tariffs is dependent on the network tariff assignment and re-assignment policies of the electricity distributors.

The key elements of SA Power Networks' proposed tariff assignment and re-assignment procedure are summarised below:

- To reassign residential and small business customers with smart meters to the relevant default time of use tariff with the option to choose opt-in to an alternative incorporating a demand component

[78] Australian Energy Market Commission, *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015; National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, 26 November 2015.

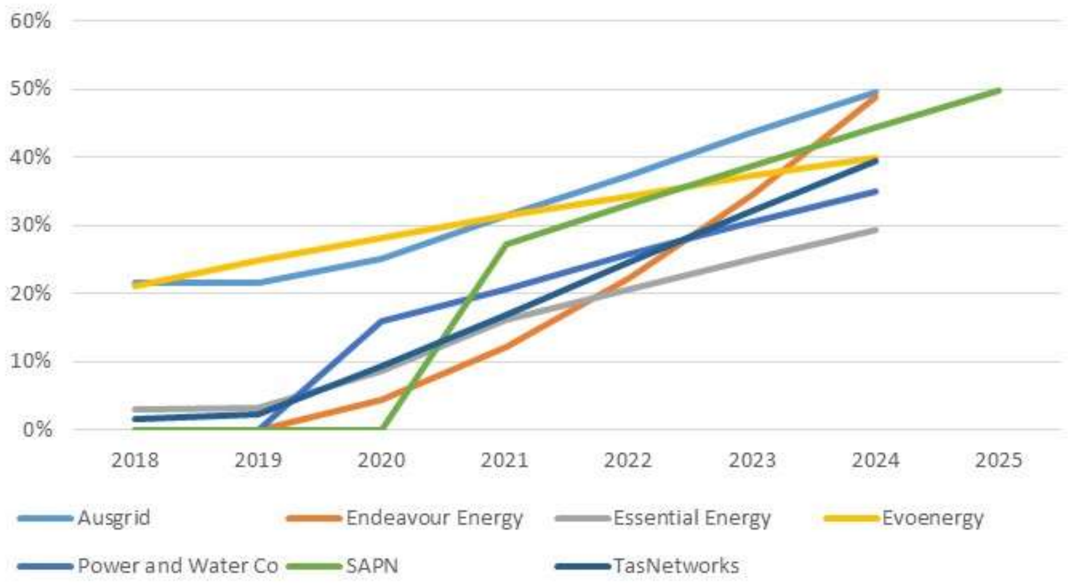
- To assign all new residential and small business customers that connect to the electricity distribution from 1 July 2020 to the relevant default time of use tariff with the option to choose opt-in to an alternative incorporating a demand component.
- To reassign existing residential and small business customers that replace or upgrade their basic accumulation meter from 1 July 2020 to the relevant default time of use tariff with the option to choose opt-in to an alternative incorporating a demand component.

These policies were informed by impact analysis which indicated:

- 80 per cent of customers without solar will have lower network bills
- only 2.5 per cent of customers with solar will pay more than $100 more each year.

The above proposed tariff assignment and reassignment procedure is expected to result in increased penetration of cost reflective network pricing in SA. This is consistent with the assignment of residential customers in other distribution networks, as shown in the figure A.4 and discussed below.

Figure A.4 Assignment of residential customers to cost reflective network pricing



Source: AER analysis.

The figure above highlights that Ausgrid and Endeavour Energy are expected to achieve the highest penetration of cost reflective pricing by the end of their regulatory period. Although in the following year SA Power Networks is also expected to reach around 50 per cent of customers with cost reflective network tariffs. This shows that while networks are approaching network tariff reform in a manner tailored to their network conditions and customer preferences, the pace of reform is accelerating over the next five years.

A.4 Network costs, revenues and average network prices

The appropriateness of the proposed pace of network tariff reform must be assessed in the context of the customer impact principle in Chapter 6 of the NER.[79] While we are yet to approve the final numbers for opex, repex and augex (capex), we consider it useful to explore SA Power Networks' proposal and the implications for network tariffs. In this regard, we note SA Power Networks proposed increases in network prices equivalent to CPI over the next five years, following the proposed P-nought reduction for 2020–21.

Table A.1 SA Power Networks' proposed standard control revenue requirement

Smoothed Distribution Revenue Requirement	2019-20	2020-21	2021-22	2022-23	2023-24
Capex ($m)	361	375	339	337	329
Opex ($m)	298	302	306	310	314
Smoothed revenue ($m)	783	783	783	783	783

Source: SA Power Networks.

SA Power Networks proposed a P-nought reduction in the first year of the next regulatory control period for the revenue requirement for the provision of standard control distribution services. This will reduce the annual network bill by $40 for residential customers and $111 for small business customers in 2020–21.[80] Over the regulatory period, SA Power Networks is proposing to keep revenue stable at around $3915 million ($2019-20) compared to $3909 million ($2019-20) over the 2015–20 regulatory period.

If approved, this will provide an opportunity to progress tariff reforms in the first year of the next regulatory control period. It should also be noted that it is easier to gain overall customer acceptance of cost reflective pricing if the majority of customers are likely to pay less during the period that tariffs are being transitioned to cost reflectivity.

A.5 Network Capital Expenditure

As highlighted in figure A.6 below, replacement is the largest component of the proposed capital expenditure for SA Power Networks in the next regulatory control period. Augmentation is the second largest component, although of the proposed $391 million over the next 2020–25 only $155 million is for distribution network capacity. SA Power Networks states the remainder of the proposed augmentation is for reliability, environmental, safety, strategic and PLEC (undergrounding) projects.[81]

The relatively high importance of replacement capital expenditure in the cost function of most distributors in Australia has implications for the design of cost reflective network

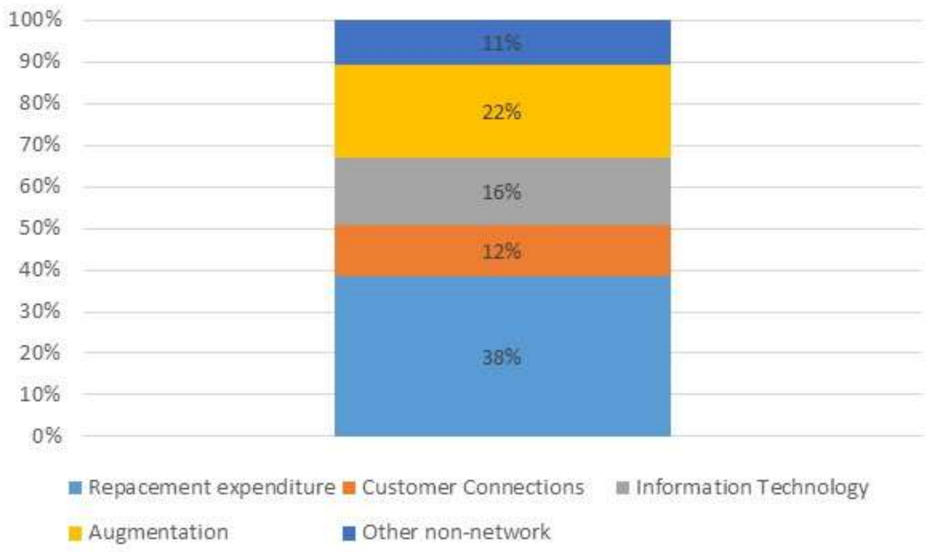
[79] NER, cl 6.18.5(h).

[80] SA Power Networks, *2020-25 Regulatory Proposal Overview*, p 33.

[81] SA Power Networks, *2020-25 Regulatory Proposal Overview*, p 34.

tariffs.[82] The relatively low proportion of augex dedicated to increasing the capacity of the network supports SA Power Networks' proposal to focus on improving network utilisation and moving towards more effective recovery of residual costs, with less focus on peak pricing.

Figure 18A.5 SA Power Networks' proposed capital expenditure by category - 2020–25 Regulatory Control Period



Source: SA Power Networks.

A.6 Network use of system tariffs

Network Use of System (NUoS) tariffs in Australia comprise the following components:

- Distribution Use of System (DUoS) component – this relates to the cost of providing standard control distribution services, plus an adjustment for the overs and unders account of the revenue cap control mechanism and any pass through amounts approved by the AER.
- Transmission Use of System (TUoS) component – this relates to the cost of providing standard control transmission services, plus an adjustment for the overs and unders account of the revenue cap control mechanism and any pass through amounts approved by the AER.
- Jurisdictional scheme amount component – this only applies where a electricity distributor is required to contribute to a Jurisdictional scheme imposed by a state or territory government, plus an adjustment for the over/ under recovery of the actual contribution amount payable.

82 AER, *Final Determination - Tariff structure statements - Ausgrid, Endeavour and Essential Energy*, February 2017, pp.92-93.

There are a range of current network tariff structures for residential and small business customers in the NEM, as summarised below:

- It is common for residential and small business customers with accumulation metering to be assigned to a flat network tariff comprising a fixed charge and a uniform energy charge. The only exceptions are Ergon Energy and Endeavour Energy that currently have inclining block tariff structures currently in place.
- A time of use energy tariff is commonly available for residential and small business customers with interval metering. These tariffs typically comprise a fixed charge and peak, shoulder and off-peak energy charges. The peak times vary considerably across electricity distributors, reflecting in part differences in load profiles.
- Electricity distributors are also introducing demand tariffs to residential and small business customers with smart metering installed. These tariffs typically comprise a fixed charge, a peak demand charge and an anytime energy charge.[83] As with the time of use tariffs, the peak times applying to the demand charge vary considerably across electricity distributors.

The following figure shows that the current reliance on anytime energy charges from a NUoS revenue perspective varies markedly across individual electricity distributors. Power and Water Corporation, TasNetworks and Endeavour Energy are estimated to have the highest reliance on anytime energy charges, whereas Evoenergy will have the lowest reliance in line with their relatively high penetration of cost reflective pricing in the residential and small business customer segment. Despite proposing to increase the proportion of revenue recovered from fixed charges between 2020 and 2025, SA Power Networks is starting from a lower base with only 15 per cent of revenue recovered through these parameters in 2020–21.

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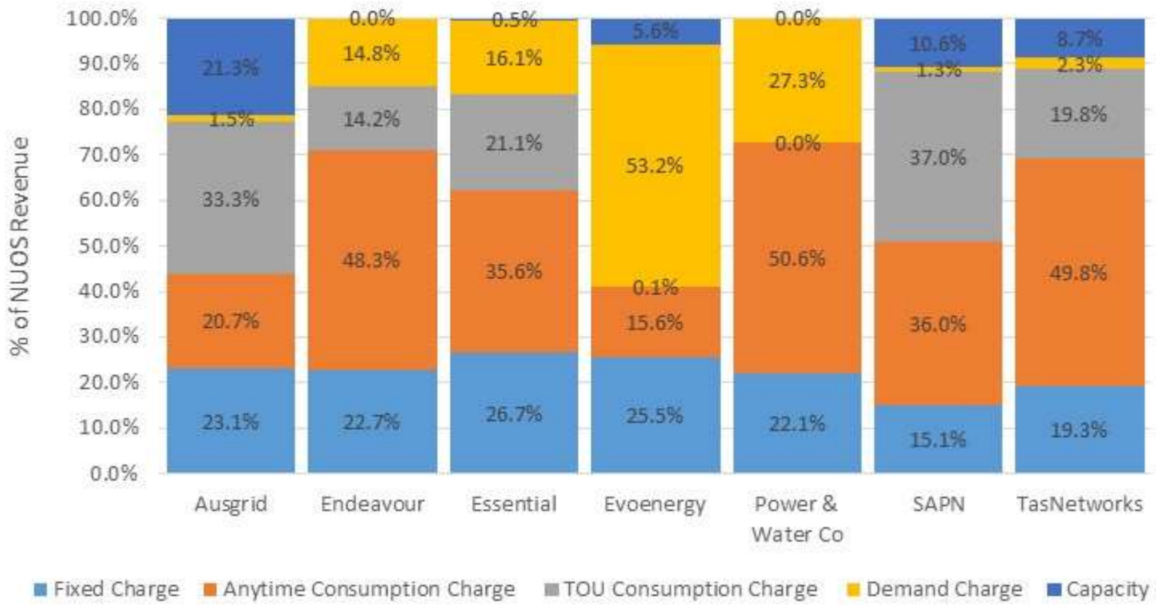
[83] The peak demand charge applies to the customer's highest kW demand recorded during the peak charging window over the billing period.

Figure A.6 Current network revenue share by charging parameter by selected electricity distributor



Source: AER analysis.

A.7 Comparison with other electricity distributors pricing proposal in next regulatory control period

Once satisfied the proposal complies with the customer impact principles and is consistent with the pricing principles, the AER focuses on the Network Pricing Objective.[84] Whether the network pricing approach set out in SA Power Networks' tariff structure statement proposal will contribute to the achievement of the Network Pricing Objective in Chapter 6 of the NER and in turn the broader National Electricity Objective in the NEL is a key consideration for reviewing the broader strategy. Compliance with the distribution pricing principles in the NER requires that the electricity distributor make progress towards long run marginal cost-based pricing and the efficient recovery of residual costs. These issues are explored below.

Progress towards efficient recovery of residual costs

The efficient recovery of residual costs requires that these costs are recovered from network customers in a manner that minimises the distortion to efficient network usage. The fixed charge has the potential to be an economically efficient way to recover because changes in the level of the fixed charge typically do not influence the investment, network connection and consumption decisions of electricity distribution customers. Nevertheless it is important from a compliance perspective that the rate of fixed charge increase does not contravene the customer impact principle in the NER.[85]

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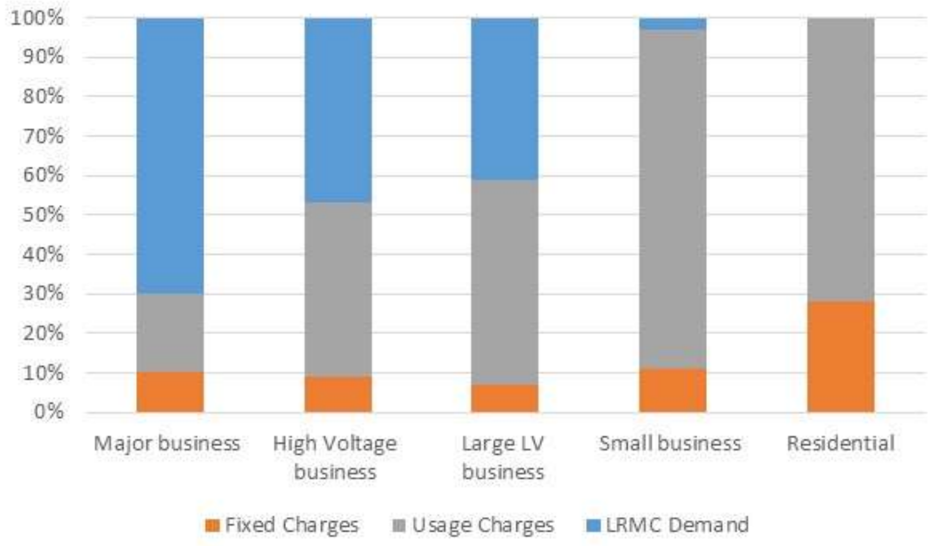
84 NER, cl. 6.18.5(d).

85 NER, cl. 6.18.5(h).

Figure A.7 Residual cost recovery by charging parameter by SA Power Networks



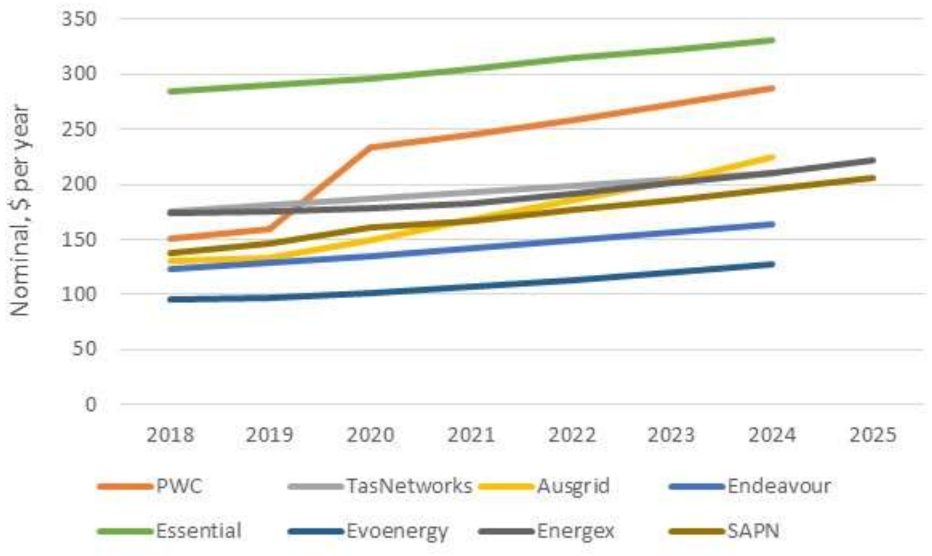
Source: SA Power Networks.

SA Power Networks proposed to increased fixed charges to recover more of residual costs, reflecting the sunk nature of these costs. However, this graph shows the proportion of residual distribution costs recovered through each parameter once revenue from LRMC pricing signals has been accounted for. For total NUoS cost recovery, SA Power Networks agreed with customers to keep the proportion of fixed charges in NUoS to 22.5 per cent of the residential tariff.[86]

The figure below provides insight into the extent that the electricity distributors with recently determined or open regulatory determinations propose to increase the level of the fixed charge of their residential anytime energy network tariff over the next five years. While SA Power Networks negotiated with its customers to increase the fixed charge for residential customers by $10 each year, the resulting price at the end of the regulatory period remains the third lowest of these networks.

[86] SA Power Networks, *Tariff Structure Statement 1 July 2020 – 30 June 2025,* January 2019, p. 66.

Figure A.8 Residential fixed charges by selected electricity distributor



Source: AER analysis.

Progress towards long run marginal cost price signals

Consistency with this aspect to the distribution pricing principles set out in the NER is achieved by setting peak charges reflective of long run marginal cost estimates, ensuring peak charging windows accurately reflect times of network congestion and assigning more customers to cost reflective network tariffs.

The key drivers of the assignment of customers to cost reflective tariff are the penetration of interval metering and the procedure for assigning and re-assigning customers to tariffs.

Electricity distributors expect to see a material increase in the penetration of interval metering over the next five years. This will enable these electricity distributors to potentially achieve a substantial increase in the penetration of cost reflective pricing in the residential customer segment, see figure A.8 above.

A.8 Tariff classes

Electricity distributors are required under clause 6.18.3(b) of the NER to group their customers into tariff classes for the purpose of setting the prices of standard control network services. Tariff classes are important because the efficiency bounds test and the side constraints are both applied at the tariff class level.

The following table provides a summary of the current tariff classes for each electricity distributors. It is clear from this analysis that there is a considerable variation in the extent of tariff class disaggregation across electricity distributors, particularly in respect to customers connected at the low voltage level of the electricity network.

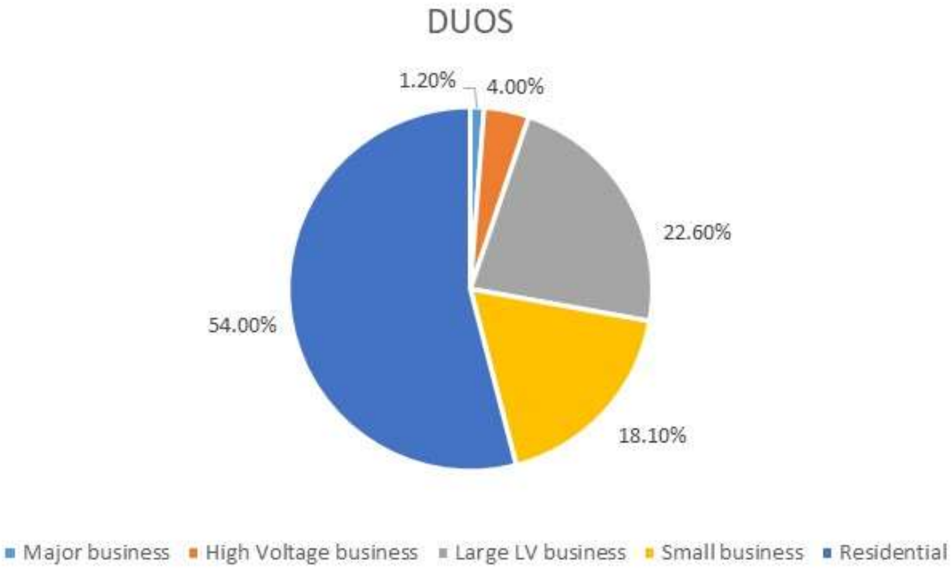
Table A.2 Comparison of current tariff classes by selected electricity distributor

Connection characteristic	SA Power Networks	QLD distributors	Ausgrid	Endeavour Energy	Essential Energy	TasNetworks	Evoenergy	Power and Water
Low voltage (230/400 V)	Residential Small business using <160 MWh pa Large business using >160 MWh pa	Standard Asset Customers (including unmetered)	Low Voltage	Low Voltage Energy Low Voltage Demand	Low Voltage Energy Low Voltage Demand	Residential Small Low Voltage Large Low Voltage Uncontrolled Energy Controlled	Residential Commercial Low Voltage	Less than 750 MWh per annum More than 750 MWh per annum
High Voltage (11 or 22 kV)	Large business HV	Connection Asset	High Voltage	High Voltage	High Voltage	High Voltage	High Voltage	High Voltage
Sub-transmission Voltage (33, 66 or 132 kV)	Major business	Individual Tariff Calculation	Sub-transmission Voltage Transmission-connected	Sub-transmission Voltage Inter-Distributor Transfer (IDT)	Sub-transmission Voltage	Individual Tariff Calculation		
Unmetered Supply			Unmetered	Unmetered	Unmetered	Unmetered		

Source: AER analysis.

In terms of revenue recovery from these classes, the following figure provides a comparison of the forecast distribution use of system revenue share by tariff class for SA Power Networks in 2020–21. As this shows, SA Power Networks recovers more than half of its distribution revenue requirement from residential customers. While large and small businesses connected to the LV network contribute a further 41 per cent.

Figure A.9 SA Power Networks DUoS revenue share by tariff class



Source: AER analysis.

But the proportion of revenue recovered from each tariff class partly reflects both the relative number of customers and relative consumption volumes of each tariff class.

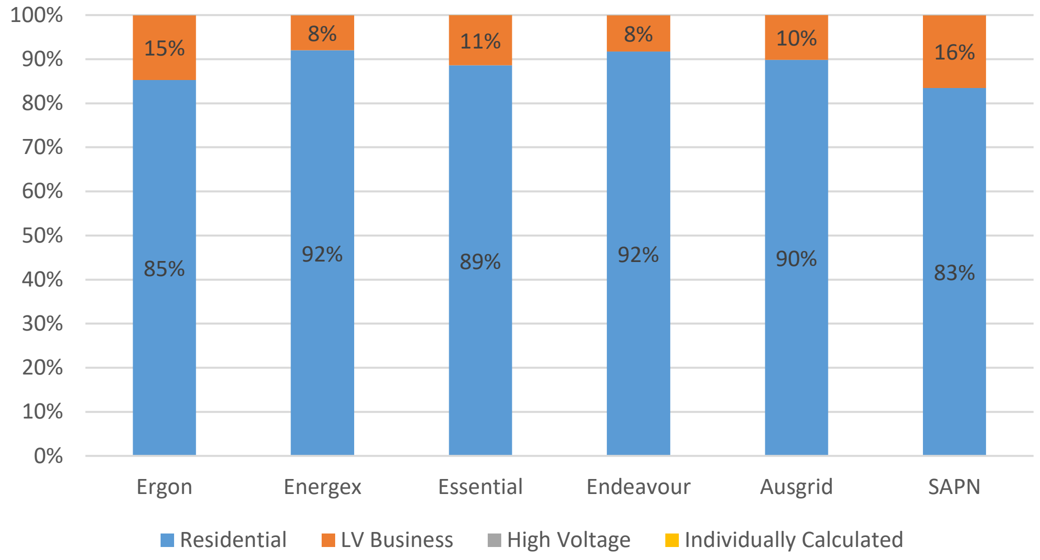
A.9 Customer numbers

The following figure shows that residential customers account for between 83 per cent and 92 per cent of all customers served by electricity distributors. The second highest share is low voltage connected business customers, which account for between 8 per cent and 16 per cent of total distribution customers. High voltage customers account for typically less than 1 per cent of all distribution customers. There are also a small number of very large customers connected to either the high voltage or sub-transmission voltage level of the electricity network that are assigned to a site-specific individually calculated tariff. These tariffs are more cost reflective than the tariffs for small customers both in terms of structure and price levels.[87] But SA Power Networks,

[87] For example - the transmission component of an unpublished tariff is typically set to reflect the location-specific costs incurred by the electricity distributor in relation to the provision of standard control services to the customer's specific connection point.

like most other electricity distributors, has less than 50 customers on the more bespoke network tariffs. This reflects the increased complexity and higher transaction costs associated with developing and maintaining these types of network tariffs.

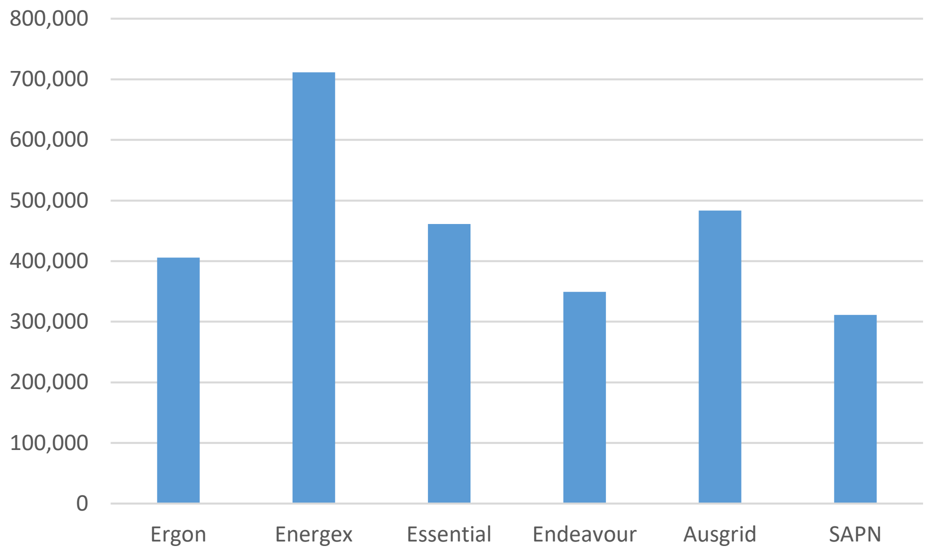
Figure A.10 Current share of customers by tariff grouping by selected electricity distributor



Source: AER analysis.

Electricity distributors also offer controlled load tariffs. Unlike primary network tariffs, controlled load tariffs require that the customer allow the electricity distributor to interrupt or restrict the supply of energy to the customer's connection point. SA Power Networks has relatively low numbers of customers on controlled load tariffs. However, this may reflect SA Power Networks' decision to align residential controlled load pricing with the default time of use to provide a clear signal to the retailer and place more emphasis on interactions between end users and their retailers. Additionally, in the Riverland area which faces a localised constraint, SA Power Networks chose to continue to build on its trials with price signals for businesses to create a demand response rather than pursuing controlled load.

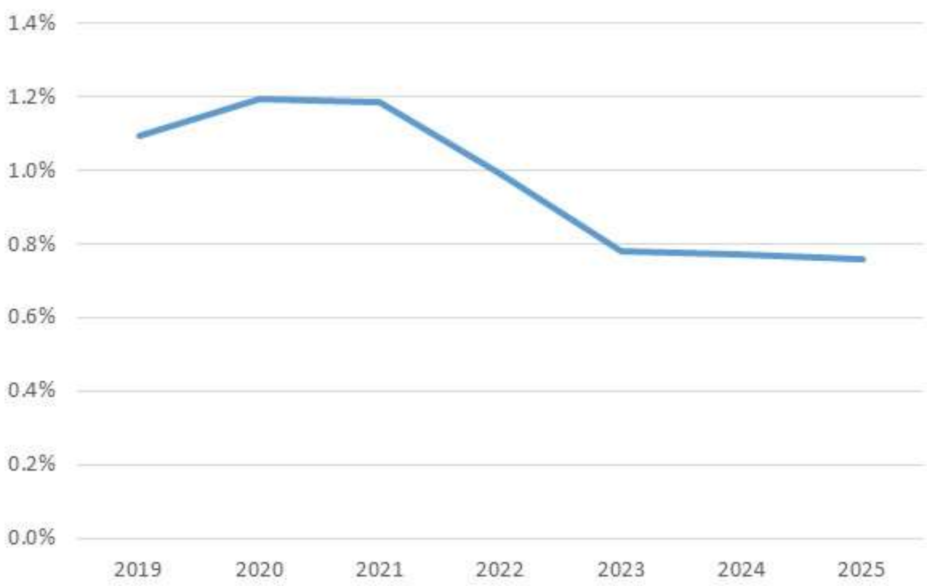
Figure A.11 Current number of customers on network controlled load tariffs by selected electricity distributor



Source: AER analysis.

In terms of total customer numbers, SA Power Networks is forecasting the total number of customers connected to its electricity distribution network to grow by around 1 per cent a year over the next regulatory control period, reflecting the projected growth in population.

Figure A.12 Annual growth rate in SA Power Networks' customer numbers

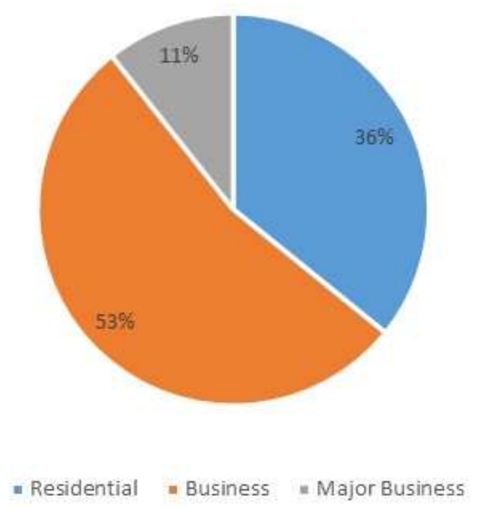


Source: AER analysis.

A.10 Customer demand

While only a small number of business customers are connected at the higher voltage levels of the electricity network, the large size of these customers means that they account for a material share of SA Power Networks' total energy consumption each year, as shown in figure below.

Figure A.13 Current annual energy consumption by tariff segment – SA Power Networks



Source: AER analysis.

SA Power Networks is forecasting total energy consumption to grow modestly at an annual rate of 0.3 per cent over the next regulatory control period. This is consistent with the AEMO operational energy consumption forecast under the neutral scenario which predicts that grid supplied energy consumption across the NEM will remain flat as a result of forecast strong growth in roof top solar PV projected to offset forecast growth from expected increases in population and economic activity.[88]

The underlying composition of energy consumption by major customer segment is changing over time, reflecting the influence of energy conservation, uptake of energy efficient appliances and new energy technologies, price response and changes in the underlying structure of the economy away from energy-intensive sectors.

A key driver of energy consumption trends over the medium to long term is the adoption of Distributed Energy Resources. The following table provides a regional comparison of the installation of Solar Photo voltaic systems by state and territory over the ten year period to 2019.

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[88] AEMO, *Electricity Statement of Opportunities*, August 2018, p. 36.

Table A.3 Solar PV system installations by jurisdiction

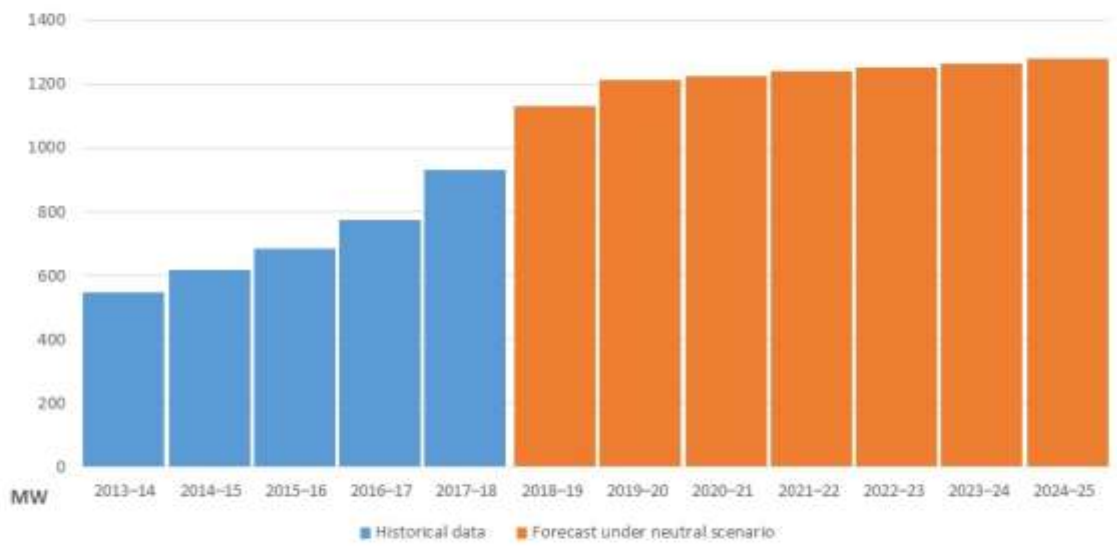
Year	NSW	QLD	SA	VIC	NT	TAS	ACT
2010	69,988	48,697	16,705	35,676	637	1,889	2,323
2011	80,272	95,303	63,553	60,214	401	2,475	6,860
2012	53,961	130,252	41,851	66,204	513	6,364	1,522
2013	33,998	71,197	29,187	33,332	1,024	7,658	2,411
2014	37,210	57,748	15,166	40,061	1,026	4,207	1,225
2015	33,477	39,507	12,081	31,345	1,197	2,020	1,066
2016	29,495	34,422	12,604	26,724	1,745	2,487	1,001
2017	43,210	46,446	16,190	31,357	1,950	2,393	1,946
2018	59,023	54,802	21,776	46,821	2,356	2,627	3,172
2019	28,254	27,809	9,874	26,477	1,245	967	1,348

Source: 2019 Clean Energy Regulator.

The growth in the number of solar PV installations over the past decade reflects the falling real price of these systems, incentives under existing energy-based electricity tariff structures and the influence of government initiatives.

Figure A.14 shows a comparison of the historical and forecast capacity of solar PV systems installed in the SA Power Networks' region. It is clear that while installed capacity increased at an average annual rate of 14 per cent between 2013–14 and 2017–18, this growth rate is projected to slow to 1 per cent over the regulatory period 2020–25 under AEMO's neutral scenario.

Figure A.14 Total Capacity of Roof top Solar PV installations



Source: AEMO South Australia Electricity Report 2018.

On the demand side, in 2018 AEMO estimated that around 15MW of embedded battery capacity had been installed in the SA Power Networks' region. Under their Neutral scenario which assumes moderate growth in DER, installed behind the meter storage capacity is forecast to reach 180MW by 2027–28.[89] AEMO is also forecasting around 155GWh of additional demand from electric vehicle charging by 2027–28.

SA Power Networks noted in its proposal that over the regulatory period AEMO forecasts battery capacity to double from 85.9MW (223.3MWh) in 2019–20 to 174.4MW (453.4MWh) in 2024–25 with the majority of this capacity owned by residential customers.[90]

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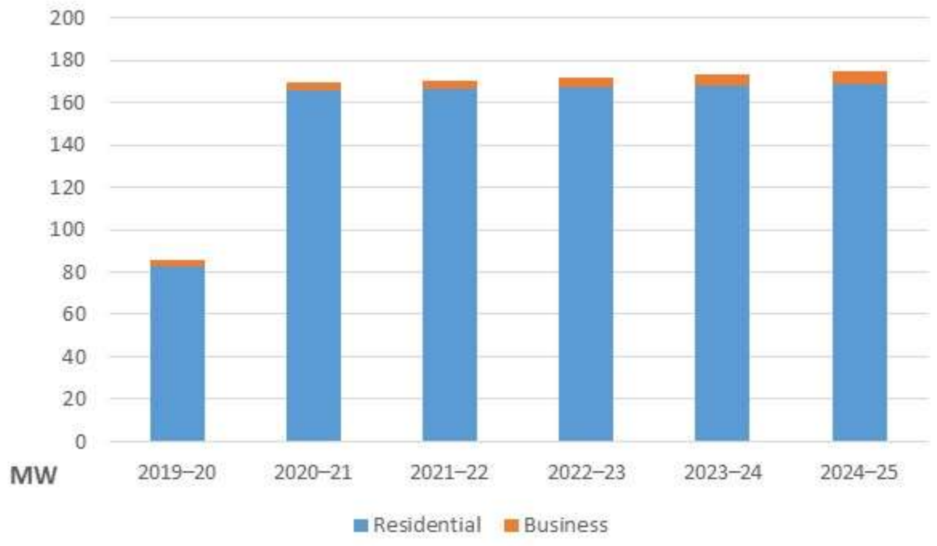
89 AEMO, *South Australian Electricity Report,* November 2018, p. 17.

90 SA Power Networks, *Tariff Structure Statement 1 July 2020 – 30 June 2025,* January 2019, p. 29.

Figure A.15 Total Capacity of Battery Storage installations



Source: SA Power Networks' TSS Proposal.

A.11 Peak demand

While total demand affects the utilisation of the network and consumption base from which revenues can be recovered, it is the peak demand that determines the size of the network required to serve customers. This means it is peak demand that drives the investment costs (augex) and needs to be considered further in assessing SA Power Networks' proposed strategy.

SA Power Networks is predominantly a summer constrained electricity distribution network, where the network is more likely to be constrained on extremely hot summer days. It is under these weather conditions that peak demand is highest due to the simultaneous use of air conditioning and other cooling appliances, such as fans and evaporative coolers. It is also the case that the capacity of the electricity network is reduced by ambient temperatures.

SA Power Networks is forecasting modest growth in peak demand over the medium term with annual growth in system-wide peak demand over the 2020–25 regulatory control period forecast to average around 0.3 per cent.[91]

Figure A.16Figure provides SA Power Networks' forecast and historical weather corrected system-wide peak demand at the 10 per cent Probability of Exceedance which is used to inform their calculation of long run marginal cost.

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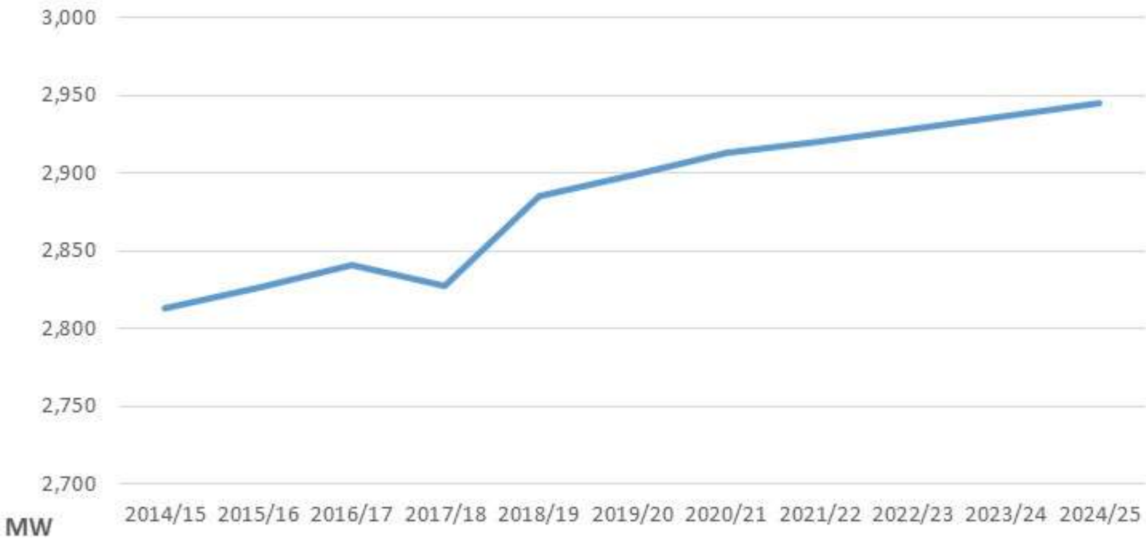
[91] SA Power Networks, *Long Run Marginal Cost Model*, January 2019.

Figure A.16 Forecast of SA Power Networks' peak demand in next regulatory control period



Source: SA Power Networks.

The moderate forecast growth in system-wide peak demand over the next five years is consistent with the AEMO's prediction of long-term growth in peak demand for SA Power Networks. Interestingly, this contrasts with the forecast peak demand trends in other regions of the NEM, as indicated by AEMO forecasting peak demand in most NEM regions to either decline or stabilise over this forecast period, see table below.

Table A.4 Forecast of maximum demand by NEM region – 50 per cent POE

NEM region	Season	2019	2023	2027	2037
New South Wales	Summer	12,366	12,442	13,172	14,870
	Winter	11,820	12,073	12,970	15,628
Queensland	Summer	8,533	8,626	8,857	9,853
	Winter	7,375	7,855	8,242	9,427
Victoria	Summer	8,983	9,249	9,679	11,371
	Winter	7,573	7,861	8,323	10,378
South Australia	Summer	2,901	2,951	3,004	3,305
	Winter	2,358	2,432	2,483	2,811
Tasmania	Summer	1,344	1,359	1,367	1,450
	Winter	1,675	1,692	1,703	1,825

Source: AEMO 2018.

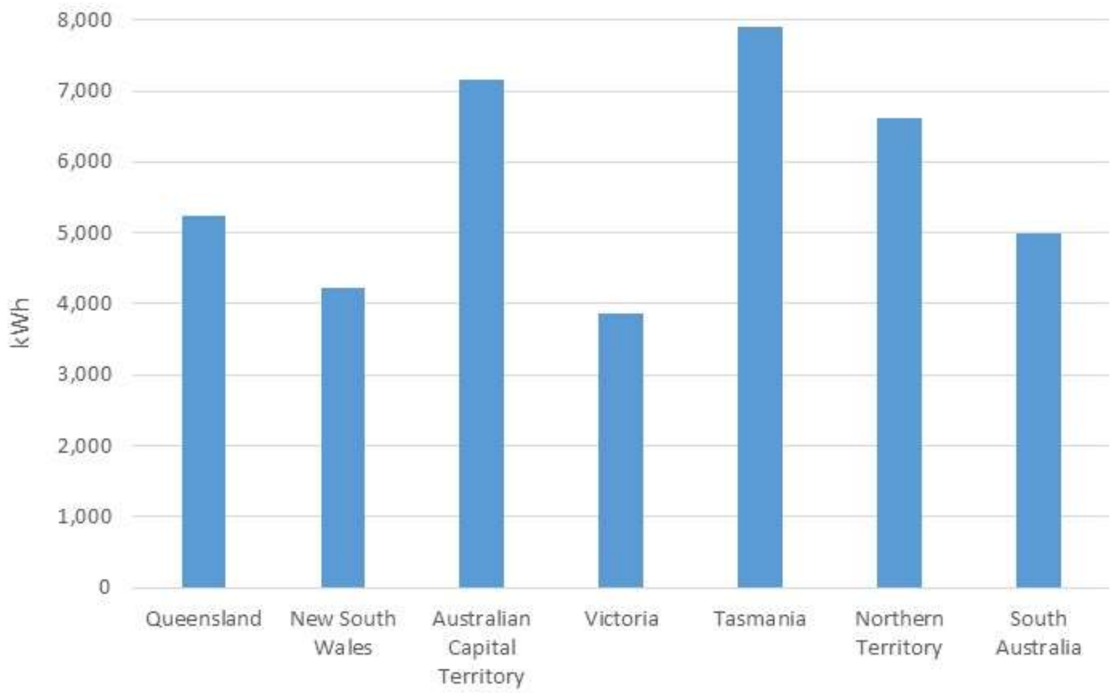
It should be noted that changes in system-wide peak demand at a regional level may not necessarily be associated with changes in network costs, given that the need to invest in additional network capacity will also be influenced by the presence of excess capacity and localised variations in maximum peak demand growth.

A.12 Energy Consumption per residential customer

Electricity distributors focus on peak demand as a cost driver for their operations, but for residential customers it is the size and timing of their consumption which will affect the size of their network and retail electricity bill.

The following figure highlights the differences in annual electricity consumption for a representative residential customer by jurisdiction.[92]

Figure A.17 Current annual electricity consumption per household by NEM region



Source: AEMC 2018.

This variation reflects regional differences in temperature conditions, the mix of appliances and the market penetration of gas for heating and cooking. The influence of colder temperatures have resulted in Tasmania and the Australian Capital Territory having the highest annual residential electricity consumption in NEM. Whereas Victoria and New South Wales have the lowest annual residential electricity consumption in the

[92] AEMC, Electricity Price Trends, December 2018.

NEM, in part reflecting the higher penetration of gas for heating and cooking. Annual residential electricity consumption is similar in South Australia and Queensland

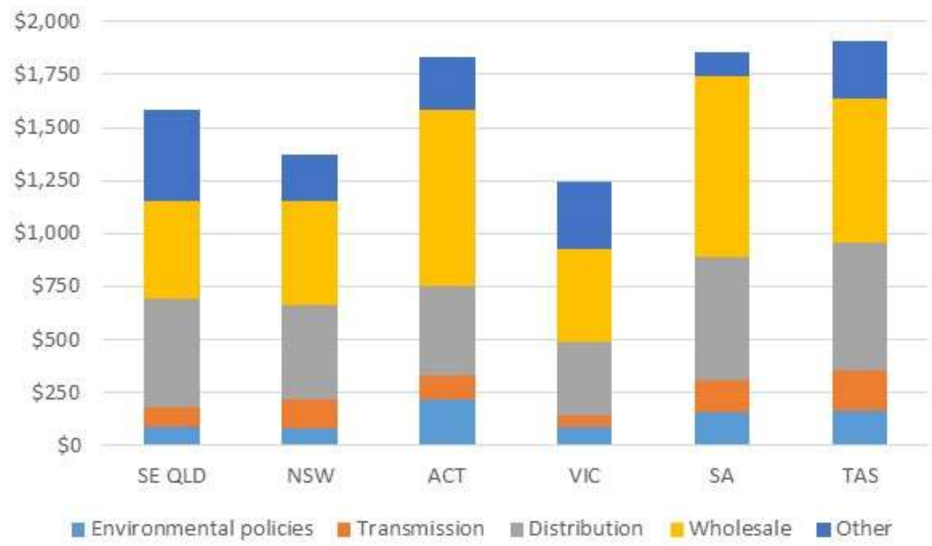
As with most regions in the NEM, average energy consumption per residential customer is expected to decline over the over the next regulatory control period given that the impact of continued strong uptake of solar PV will have a moderating influence on the growth in overall energy consumption from the grid over this period, together with the relatively high forecast growth in customer numbers.

A.13 Retail electricity price components

When the retail electricity market is competitive, the market offers to customers will reflect the underlying costs in the supply chain. This includes the costs of providing regulated electricity network services, retail margin, electricity purchase costs and the costs relating to environmental policy.

The following figure shows an estimate of the current supply chain cost components that underlie the annual retail electricity bill for a representative residential consumer by NEM region.

Figure A.18 2018–19 Annual electricity supply chain costs by NEM region



Source: AEMC 2018.

It is clear from the figure above that the wholesale energy purchases and the provision of electricity distribution and transmission services are the largest cost components in the underlying supply chain. Nevertheless, there is considerable variation in the relative share of each supply chain cost component across NEM regions.

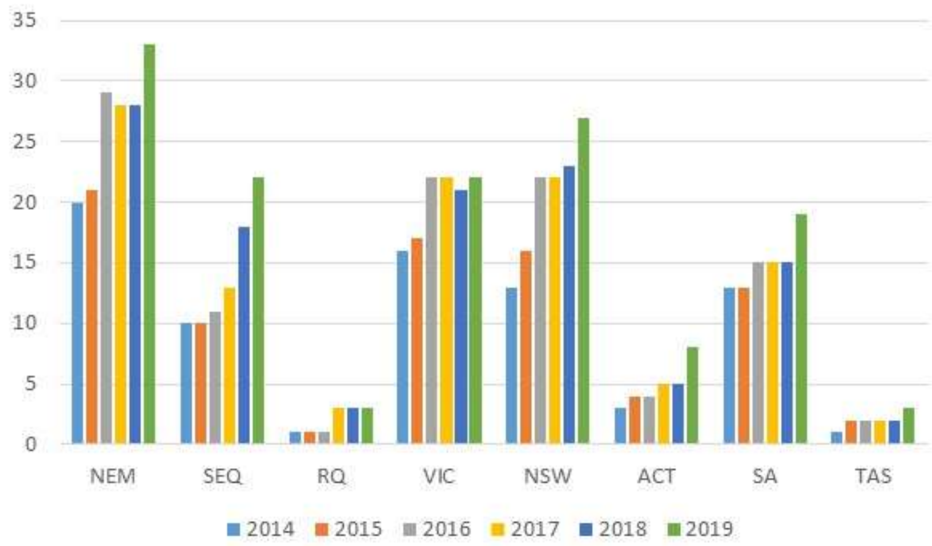
While the representative customer in South Australia faces the highest wholesale costs, their transmission and distribution costs are second only to Tasmanian consumers. This means that consumers are sensitive to changes in these parameters and can impact consideration of the customer impact principle in the context of network tariff reform.

A.14 Retail pricing behaviour

The electricity retail market in SA is competitive so all customers can choose their retailer and electricity plan. Customers who do not choose a plan are automatically moved onto their retailer's default standing offer.

The number of retailers providing offers to customers in SA has increased from 13 in 2014 to 19 in 2019. This compares to 33 retailers operating across the National Electricity Market (NEM) and is comparable to other competitive markets like Victoria and South East Queensland as the graph below shows.

Figure A.19 Active electricity retailers in the National Electricity Market



Source: AEMC 2019 Retail Energy Competition Review.

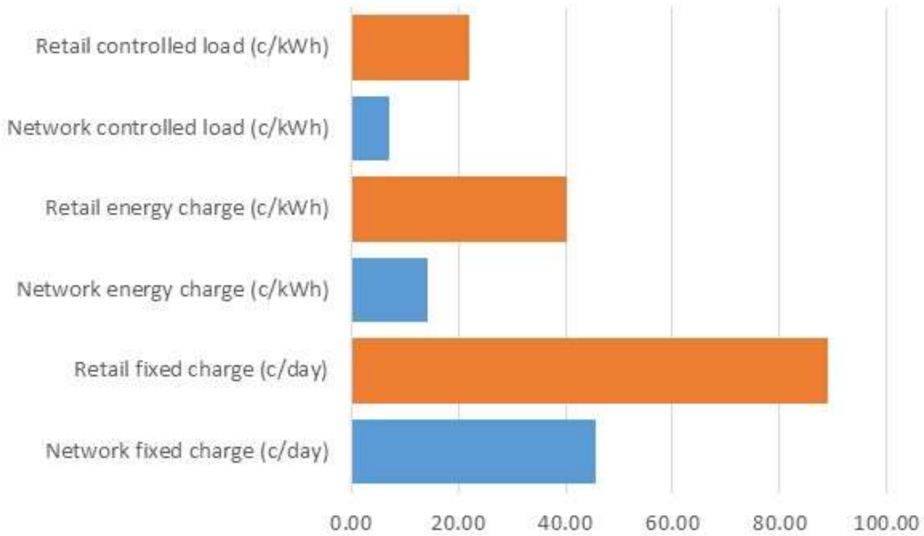
AGL South Australia is the local area retailer for all small electricity customers in South Australia. AGL is obliged to provide a standing offer to small customers[93] not signed up for a market offer.

Under its standing offer, AGL offers a single rate tariff for residential customers with two simple components – fixed charge and a single anytime charge. Consumers happy to provide AGL with some control over their load (generally hot water systems) can chose the residential standing offer of a single rate with controlled load.

[93] Small customers are defined as consuming less than 160MWh per year under the *National Electricity Law (Local Provisions) Regulations* 2013.

The following figure compares the current retail parameters for the standing offer with controlled load to the proposed underlying network costs for the legacy single rate network tariff. Although it is worth noting that the network fixed charge is the same for all residential customers and the controlled load price for customers on the single rate network tariff is set to the off-peak time of use price.

Figure A.20 Network and retail price comparison – current anytime energy tariff



Source: AER analysis.

While this is comparing a current retail offer with network tariffs proposed for next year, it shows that SA Power Networks' proposal is consistent with the retailers' current pricing behaviour. It is worth noting that AGL currently also offers a demand tariff standing offer based on the opt-in cost reflective tariff offered through SA Power Networks' current TSS. We will be interested to see how the change to a time of use network tariff will filter through to AGL and other retailers' offers.

A.15 PV Feed in Tariffs

In addition to recovering SA Power Networks' costs from managing and operating the distribution network and passing through the transmission network charges, SA Power Networks is required to recover the cost of the PV feed in tariff (FiT) scheme under the SA Government. This FiT scheme is encompassed by the rules relating to jurisdictional schemes.[94] It is important to note that while SA Power Networks recovers the cost of this scheme through the NUoS charges, it does not play any role in setting the FiT rates received by participants.

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[94] NER, cl. 6.18.7A.

This scheme is targeted at supporting households, small businesses and other non-residential small customers (i.e. consuming less than 160MWh a year). SA Power Networks proposes to recover 63 per cent of the cost of this tariff from residential customers with the remaining 37 per cent recovered from non-residential customers according to their share of DUoS. As noted above, small and large non-residential customers connected to the LV network contribute 18 per cent and 22 per cent respectively so will pay a larger share of this cost.

B Tariff design and assignment policy principles

Under the NER, the objective of tariff reform is to introduce cost reflective pricing.[95] Tariff design and assignment policy has a role in achieving this objective by influencing:

- how efficiently the tariff structures actually target customers that are driving network costs;
- the speed with which customers take up cost reflective tariffs and which customers move to cost reflective tariffs.

In our assessment of a distributor's proposed tariff structure statements, we consider the pricing principles and the network pricing objective within the NER when determining to approve the statements.

The pricing principles include two complementary principles to economic efficiency that can be summarised as the customer impact principles. We must:

- consider customer impacts of the transition towards cost reflective pricing[96]
- contemplate whether customers are going to be able to understand the charges they are likely to see.[97]

In other words, cost reflective pricing can be departed from in circumstances where doing so will promote the achievement of these two additional principles. In this appendix, we outline our policy positions on tariff design and assignment policy. We have structured the appendix as follows:

1. In what circumstances should distributors assign, or reassign, customers to a new tariff?
2. When a distributor assigns or reassigns a customer to a new tariff, what options should the customer, or retailer as the customer's agent, have to change to optional tariffs?
3. What tariffs should a distributor offer to customers, and which customers should have access to which tariffs?
4. Should any aspects of tariff design and assignment be consistent nationally, within a state or within a city?

[95] NER cl. 6.18.5(a).
[96] NER cl. 6.18.5(h).
[97] NER cl. 6.18.5(i).

B.1 When should tariff assignment happen?

Distributors charge retailers network tariffs for each class, or type, of customer. Customers can be households, low voltage or high voltage commercial, or sub–transmission users connected to the high voltage network. Each can face a different network tariff structure and charge.

A distributor's tariff assignment policy are the rules the distributor follows to allocate network tariffs to customers. We regulate distributors' tariff assignment policies when we approve tariff structure statements, which must contain such policies.

Tariff assignment is when, in accordance with its approved tariff structure statement, the distributor decides what tariff to apply to a new customer (i.e. a new connection).[98]

In contrast, tariff reassignment is when the distributor switches an existing customer from one tariff to another tariff.

We consider that distributors should:

- assign new customers to cost reflective tariffs upon initial connection, which would include a smart meter under current contestability rules
- reassign established customers to cost reflective tariffs when they upgrade their connections through either:
    - adding embedded generation or
    - upgrading to three-phase power
- reassign established customers who receive a new smart meter as part of a retailer's meter replacement programme.

This approach balances the need to transition towards cost reflective tariffs with the impact a change in tariff structure might have on customers' ability to control their bills and engage in the electricity market for their long-term benefit. It recognises that customer support for distributors' tariff strategies and their ability to understand these tariff strategies is an important element of fostering and maintaining users' support for tariff reform generally.[99] While we will assess each proposal on its merits, if distributors adopt similar (re)assignment triggers there will be a more regular and consistent pace of tariff reform across distributors and jurisdictions.

New customers should face cost reflective tariffs

When new customers connect to the distribution network, the distributor should assign them a cost reflective tariff immediately.

98 Retailers are not obliged to pass through network tariffs or network tariff structures to customers in their electricity retail bills.

99 NER cl. 6.18.5.

We consider that it is appropriate for distributors to assign new customers immediately to cost reflective tariffs for the following reasons:

- such tariffs incentivise efficient use of the network and investment in energy efficiency in the construction of a new building/premise[100]
- newly connected customers are less likely to be surprised by their network charges even where they are moving premises. This is because as they either have no prior tariffs to compare with or prior tariffs were at another connection with different appliances and heating, cooling or lighting needs.

Upgrading customers should face cost reflective tariffs

Existing customers may decide to upgrade their electricity connection by:

- installing embedded generation, such as rooftop solar
- increasing the capacity of their connection, such as installing three-phase power.[101]

Distributors can reasonably expect customers that upgrade their connections to understand that the upgrade will impact their network charges. These customers, along with the businesses installing rooftop solar and three-phase power, are in a position to understand the impact of a cost reflective tariff on their network charges. Put another way, they are in a position to appreciate that their decisions will have costs for the network—tariffs should recoup those costs from those same customers. They should also reward those consumers for changing their behaviour to reduce the impact on network, for example shifting demand from battery storage from the coincident peak should result in lower network charges.

We note that the AEMC’s metering rules state customers that upgrade to embedded generation or three-phase power will receive a new meter. Therefore, they are automatically captured under the ‘new meter’ trigger.

Mitigating the impact may be appropriate for meter replacements

Under the AEMC's tariff reforms, metering providers must replace faulty accumulation meters with smart meters—this is automatic without any action by customers on their behalf.

Under the NER, we consider that customers who receive a new smart meter should face cost reflective tariffs when they can understand those tariffs and influence their charges through their usage decisions.

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[100] For example, in NSW new residential dwellings must obtain a BASIX certificate to demonstrate that the building complies with energy efficiency standards. Although BASIX does not target peak demand, complying with its energy targets should lead to some reduction in peak demand. NSW Government, BASIX see: https://www.planningportal.nsw.gov.au/planning-tools/basix.

[101] We consider this to be a material change to connection arrangements.

For customers those that receive a new smart meter on account of their accumulation meter being faulty, these customers are not actively engaging with their electricity supply. Circumstances beyond their control are impacting their connection. We do not consider such customers can necessarily understand the impact of a cost reflective tariff immediately. Therefore, each distributor should consider whether a 12-month data sampling period or a transitional approach may be warranted. This delay will assist customers to better understand their load characteristics and be provided sufficient information to make an informed decision when selecting a retail pricing offer.

The 12-month grace period is to help customers to understand a full year of their consumption and demand profile (i.e. so they understand their demand characteristics in all seasons). While a transitional tariff with prices increasing over a predetermined period will allow consumers to understand and respond to weaker signals. This will help them adjust to the new cost reflective network tariff to which they will be reassigned following conclusion of the grace period and the likely impact on their retail bills.

We consider that customers with new connections or have upgraded their connection are more likely to understand the impact of cost reflective network tariffs on their retail bills. This is because these customers are:

- actively engaged either by investing in upgrading their connections or through considering electricity efficiency when preparing for a new connection, and
- expecting to see a change in their retail electricity bills due to the changing or upgrading their network connection.

Retail price regulation will influence tariff reassignment

Retail price regulation is a relevant consideration in our decision on acceptable reassignment practices. However the nature and scope of retail regulation varies between jurisdictions, for example retailers in SA Power Networks' network face the default market offer regulation for relevant customers while those in Power and Water Corporation's network in the Northern Territory face more comprehensive regulation. In the Northern Territory, the Government caps and subsidises flat retail electricity tariffs. The retailer faces cost reflective tariffs from the distributor but converts these to a flat tariff for customers under the regulatory arrangements in the Territory. This means there is no customer impacts or change to customer understanding that need to be considered following reassignment which supports more aggressive approach to tariff (re)assignment.

B.2 Is choice of network tariff appropriate?

In our 2017 Tariff Structure Statements' final decision, we indicated that distributors should propose default assignment to cost reflective tariffs in their following TSS.[102] SA Power Networks proposed to do this for 2019–24.[103] With default assignment to cost reflective tariffs, distributors need to consider the following strategies:

- prescribed tariff assignment – where customers must remain on the default network tariff the distributor assigned them. This is also known as mandatory tariff assignment
- choice of cost reflective tariffs – where customers can choose between a suite of alternative cost reflective tariffs (but not including anytime tariffs) instead of being prescribed to a default network tariff.

We are comfortable that distributors should offer customers a choice of cost-reflective networks tariffs to be included in their retail bill as allowing customers to choose between a suite of tariffs enables them to match their behaviour to price signals. This offers customers the ability to choose the tariff they understand best—and presumably will therefore respond to—and mitigates any potential adverse cost impacts from the move to cost reflective tariffs. This engenders greater customer acceptance of change.

Anytime tariffs are not cost reflective

Opt-out to anytime tariffs are popular with customers and retailers.[104] They give the retailer the ability to face flat energy charges. These charges are easy for customers to understand.[105] However, they do not reflect the cost drivers of the distribution business. That is, they charge customers the same amount per unit of electricity transported during peak and off-peak periods. This signals too much usage during the peak, and insufficient amounts in off-peak, potentially requiring unnecessary investment that can drive up network costs long term. That's not in the long term interest of customers.

The capacity of the distribution network is a significant driver of network costs. Therefore, the main determinant of how much cost customers are imposing on the network is how much they demand when the network, in their geographic area, is approaching its capacity constraints. Demand tariffs and time of use tariffs target time periods where capacity constraints are more likely to occur.

We consider that distributors should no longer offer customers who are on a cost reflective tariff the ability to opt-out to anytime energy network tariffs. The risks of allowing continued access to anytime tariffs – inefficient use of, or investment in, the

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102 Australian Energy Regulator, *Tariff structure statement South Australia Power Network,* Final Decision, February 2017, p. 36.

103 SA Power Networks, *2020-25 Tariff Structure Statement*, January 2019, p. 50.

104 Anytime tariffs, are any form of tariff where the network charge is not dependent on the time of usage or demand, common forms include flat tariffs, inclining block tariffs and declining block tariffs.

105 NER cll. 6.18.5(h) and 6.18.5(i).

network – outweigh the benefits of customers understanding these simple tariff structures.[106] After all, this represents nothing more than continuation of the status quo, acknowledged by policy makers as inappropriate. We note retailers can continue to offer anytime energy retail tariffs when facing cost reflective network tariffs but that is a choice for them in their ongoing management of market contracts and spot prices.

The ACCC supported prescribed tariffs

The ACCC's Retail Electricity Pricing Inquiry advocated prescribed tariff assignment, ending opt-in and opt-out tariff assignment (including cost reflective choice). To mitigate the potential negative impacts, the ACCC recommended governments provide transitional assistance, including:

- a compulsory data sampling period for customers following smart meter installation
    - this is one of the mitigating measures we recommend distributors consider
- a requirement for retailers to offer flat energy retail tariffs to customers that distributors charge more cost reflective network tariffs to
    - retail offers are outside the scope of tariff structure statements and are managed through promoting competition between retailers and monitored by regulators
- additional targeted assistance for vulnerable customers.[107]
    - these strategies can be informed by the impact analysis we encourage distributors to produce to help customers and retailers understand the potential impact.[108]

These ACCC suggestions should be considered as a package of recommended changes to the existing NEL and NER requirements.

In contrast, our current task is to apply the prevailing network regulatory framework (in chapter 6 of the NER) within which we are reviewing the current tariff structure statement proposals.

For example, in most parts of the NEM there is no requirement for retailers to offer flat retail energy tariffs, and we are not aware of any additional targeted assistance for vulnerable customers beyond hardship assistance plans and jurisdictional concessions. Given tariff structure statements are focused solely on the network tariffs charged to retailers to recover the allowed revenue, we cannot impose any requirements on retailers through our approval of distribution network service providers' tariff structure statements. We consider that prescribed tariff assignment

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106 That is, the costs of the lost opportunity for cost reflectivity (NER cl. 6.18.5(a)) outweigh the benefits of customer acceptance and understanding (NER cl. 6.18.5(i)).

107 Australian Competition and Consumer Commission, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry Final Report*, June 2018, p. xix.

108 SA Power Networks dedicated Appendix D of its TSS proposal to exploring the expected impacts of its proposed tariffs for different tariff classes and types of consumers

cannot be pursued without implementation of the complementary measures the ACCC recommended in its inquiry.

As noted above, in our review we are looking at what distributors can do on their own. Firstly, removing customer's choice through prescribed tariff assignment risks the loss of customer support. This could occur if retailers do not offer customers a flat energy tariff or innovative tariff designs that end-users can understand and feel comfortable with. Although networks can help address this through the provision of impact analysis to help customers understand how the costs retailers package for them with other costs may change.

Secondly, prescribed tariff assignment leads to a one-size fits all approach. This means that the prescribed tariff would need to be understood by all customers for them to be able to manage the impacts. Alternatively, prescribed tariff assignment on the other hand may lead to a lowest common denominator approach to tariff reform, potentially slowing the transition to cost reflective tariffs.

In spite of our concerns, we consider that coupled with complementary measures, prescribed tariff assignment can be an effective means to progress tariff reform. In the Northern Territory, Power and Water Corporation proposed a prescribed assignment policy for residential customers.[109] However, as noted earlier, the Northern Territory Government regulates and subsidises retail electricity prices.[110] This means that the move to prescribed assignment is highly unlikely to come at the cost of customer support for reform, to reduce customer choice or increase retail prices.

Customers should have choice in cost reflective tariffs

Default assignment to cost reflective tariffs (with optional alternative cost reflective tariffs available) will lead to a fast adoption of cost reflective tariffs. Indeed, it may lead to a faster adoption of cost reflective tariffs than prescribed tariff assignment, as:

- the default tariff under this approach may be more cost reflective than the prescribed tariff
- it allows for more cost reflective optional tariffs–such as critical peak pricing or rebates–that could build customer acceptance and encourage retail offerings that support a wider rollout of these more cost reflective tariff structures.

We note that the ACCC expressed concerns about an opt-out to cost reflective tariff approach. Stating:

> An alternative form of phased approach would be to introduce cost reflective tariffs at both the retail and network level to all customers on a trial basis so that they can gauge their appropriateness. Customers could then be given the opportunity to move to a less cost reflective retail and network tariff structure

[109] Power and Water Corporation, *Tariff Structure Statement,* Proposal, 16 March 2018, p. 18.

[110] Electricity Pricing Order under section 44(8) of the *Electricity Reform Act (NT)* in accordance with 13A(d) of the *Electricity Reform (Administration) Regulations,* 6 June 2017.

> without penalty if desired (a delayed opt-out approach)…. The ACCC considers that such an approach would not be ideal as it would delay the benefits from greater cost reflectivity, but it may be a workable option if used only for a short time period.[111]

The ACCC's statement reflects the fact that its recommendation is part of a package of reforms.

We consider that by allowing customers to have a choice between different cost reflective tariffs improves their support for reform. Cost reflective tariff choice would create the opportunity for customers to select:

- tariffs they can understand
- transitional tariffs that reduce the immediate impact of tariff reassignment, allowing vulnerable households to adjust to new tariff structures
- innovative retail offers such as peak demand reduction rebates or retailer owned demand management technologies.

This approach has been utilised by Evoenergy since December 2017.[112] SA Power Networks proposed this approach for customers with the option of lower time of use energy rates complemented by a seasonal, monthly demand tariff known as the 'prosumer tariff'.[113]

These methods best balances the need for cost reflective tariffs and engendering customer support for tariff reform through managing impacts and customers' ability to understand tariffs under the existing regulatory framework.

B.3 What network tariffs should distributors offer?

Given this recommendation to offer customers a portfolio of cost reflective tariffs, we need to consider what tariffs distributors should offer to customers. We will focus on tariffs for residential and small business customers, unless otherwise indicated. SA Power Networks already offers cost reflective choice to medium and large business customers.[114]

We recommend that distributors offer customers:

- time of use energy tariffs – these tariffs are as cost reflective as any other more average tariff with a pre-defined peak period and are well understood by customers

111 Australian Competition and Consumer Commission, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry Final Report*, June 2018, pp. 185–186.

112 ActewAGL, *Revised Tariff Structure Statement,* Overview Paper, 4 October 2016, p. 18.

113 SA Power Networks, *2020-25 Tariff Structure Statement,* Proposal, January 2019, p. 40.

114 SA Power Networks, *2020-25 Tariff Structure Statement,* Proposal, January 2019, p. 11

- demand tariffs – these tariffs are as cost reflective as any other more averaged tariff with a pre-defined peak period and reinforces with customers that the scale of their demand is an important cost driver.
    - To mitigate potential impacts, we consider that distributors:
        - with a dominant peak season should aim to offer seasonal monthly demand tariffs accompanied with flat energy charges
        - without a dominant season should aim to offer monthly demand tariffs with time of use energy charges
- highly cost reflective tariffs for large business customers – large business customers are well informed and spend large amounts of money on electricity, therefore distributors can assume that they understand how highly cost reflective network tariffs affect their retail bills
- flat tariffs for customers with accumulation meters – the technological limitations of accumulation meters require anytime flat tariffs, whose main benefit is simplicity.

We will also support distributors offering residential and small business customers:

- optional location based critical peak prices – these are the most cost reflective tariffs, however can be difficult to understand. Allowing customers (or their retailers) to opt-in to these tariffs will permit customers that can understand these tariffs to use and benefit from them
- optional transitional tariffs – transitional tariffs can reduce the impacts of being assigned to cost reflective tariffs. They may be valuable to some vulnerable customers who need time to adjust how and when they use electricity.

Efficient tariffs align with cost drivers

An efficient tariff sends a signal to the customer on what the customer's electricity demand costs the distributor. Under long-run marginal cost pricing, the signal should reflect the costs of the customer sustaining its behaviour over the long run. For example, when a customer buys a larger air conditioning system its electricity usage and demand will increase during hot days, the distributor's tariffs should equal its costs from meeting demand from the air conditioner, particularly on hot days.

We have heard from stakeholders that demand issues require a demand charge and energy issues require an energy charge. This position has an appealing simplicity. Unfortunately, it does not reflect reality.

Distribution businesses can indeed face two types of issues:

- demand issues are situations where capacity is driving network costs. Distributors typically experience demand issues when people get home from work on the hottest days and turn on their air conditioners or on coldest days turn on their electric heating, while transport systems and businesses are still operating at or near full capacity

- energy issues are situations where electricity usage is driving network costs. This includes any costs created by insufficient electricity usage.

Customer demand and energy usage are closely related. A customer that sustains a demand of 1kW of electricity for one hour will use 1kWh of electricity.

At a residential and small business level, distributors see demand constraints based on coincident demand. That is the total demand from customers within the feeder zone.

Distributors have proposed two approaches to increase the cost reflectivity of their residential and small business tariffs:

- demand tariffs where distributors charge customers based on their maximum 30 minute demand during peak hours each month
- time of use tariffs where distributors charge customers based on their total electricity consumed during peak and off-peak hours.

Neither structure is more cost reflective than the other, see for example our analysis of data provided by NSW distributors.[115]

Time of use tariffs are easy to understand

Time of use energy tariffs apply different charges to electricity consumption, in kWh, at different times of the day, week, and year. Distributors split days into two or three periods:

- peak – timed to correspond with the parts of the day most likely to see demand approach system or zonal capacity constraints;
- off-peak – timed to correspond with the parts of the day least likely to see demand approach system or zonal capacity constraints, and in some cases;
- shoulder – timed to correspond with the parts of the day with either a small chance of approaching a system capacity constraint or likely to see a demand approach capacity constraints in some small substation zones.

Although in some circumstances, distributors may introduce a period specific to conditions in their network. For example, SA Power Networks proposed a heavily discounted 'solar sponge' period during the day to encourage consumption during periods of high solar PV generation to address issues with falling minimum demand in LV networks.

Customers are familiar with distributors charging them (through their retailer) based on how much electricity they consume. Distributors charge customers with accumulation meters based on their energy consumption, and time of use energy tariffs are well established. In general, we consider that customers will be able to understand time of use energy tariffs. We also note that time of use energy tariffs can be relatively

[115] Australian Energy Regulator, *Tariff structure statement Ausgrid, Draft Decision,* November 2018, p. 71.

efficient, in that peak consumption is correlated with user demand during coincidental peaks.[116]

We consider that the different proposals are likely to exhibit different levels of cost reflectivity and customer understanding, based on their designs. We consider:

- more cost reflective tariffs will have more targeted peak periods. SA Power Networks' proposal does this by tailoring residential demand charges and business time of use peaks to the period between November and March, and not including peak charges during the rest of the year[117]
- easier to understand tariffs are simple for customers to remember. SA Power Networks applied this principle by having a single peak period year-round for the residential time of use tariff, which makes it easy for customers to remember when peak charges apply and change their behaviour accordingly.[118] Although this peak is not as focused as it could be given customer preference and the absence of significant constraints discussed in the reasons behind out decision which may reduce consumers' ability to respond.

However, we recommend that as customer acceptance of time of use energy tariffs increases distributors should increasingly include highly targeted, seasonal peak windows. LRMC prices are the probability of the constraint occurring within a peak/shoulder/off-peak period, divided by the total number of hours in that peak/shoulder/off-peak period. Narrow, more targeted, peak periods will require distributors to increase the peak period charges and decrease shoulder and off-peak charges (increasing the ratio of peak to off-peak charges). This will send stronger and more efficient conservation signals to customers, which should lead to efficient reductions in capital expenditure over the long term.

We consider time of use energy tariffs are sufficiently cost reflective to be approved as default tariffs.

Demand tariffs can be cost reflective

Demand tariffs charge customers based on the maximum point in time demand (typically over a 30-minute period) in kW or kVa, typically on a daily or monthly basis. Demand tariffs help cost recovery be in proportion to the network capacity customers' use. The demand charge can be:

- anytime demand – where the charge is the maximum 30-minute demand at any point in the day or month

[116] For example, our analysis of NSW distributors' interval meter data found that Ausgrid's proposed seasonal time of use energy tariffs were the most cost reflective of all tariffs proposed by NSW distributors for residential customers.

[117] SA Power Networks, *2020-25 Tariff Structure Statement,* Proposal, January 2019, p. 14.

[118] SA Power Networks, *2020-25 Tariff Structure Statement,* Proposal, January 2019, p. 14.

- peak demand – where the charge is the maximum 30-minute demand during a pre-defined peak period during the day or month[119]
- time of use demand – where the charge is the maximum 30-minute demand during each of the pre-defined peak, off-peak and shoulder periods, during the day or month.[120]

The ACCC's Retail Electricity Pricing Inquiry found that 'demand tariffs represent a good balance of cost reflectivity, simplicity and price stability':

- simplicity –the 'two-part tariff' structure (demand and energy usage) is broadly similar to current tariff structures
- cost reflectivity –while the individual's peak demand may not coincide with the network peak it emphasises to customers the relationship between network cost and demand, rather than with usage
- price stability –demand charges would lead to more stable customer bills than more cost reflective options, such as critical peak pricing.[121]

We will accept distributor's proposals to assign residential and small business customers to demand charges by default due to their level of cost reflectivity.

In our 2017 final decisions on tariff structure statements, we expressed concern with residential demand charges based on a customer's demand over a month or longer. We noted that it is not an individual customer's monthly peak demand that drives network costs, but the extent to which that customer's demand contributes to network congestion near capacity constraints.[122] As above, the ACCC also made this observation.

As well as recommending networks consider monthly maximum demand charges, we also think it is worth noting our analysis to date suggests demand tariffs perform better with embedded energy charges and seasonal demand tariffs are more cost reflective where a large majority of regions in the network area peak in the same season.[123]

We consider that there are benefits of both forms of energy charges distributors have proposed to use within their demand tariffs:

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119 For example, Evoenergy proposed a peak demand charge for customers with smart meters. Source: Evoenergy, *Regulatory proposal for the ACT electricity distribution network 2019–24 – Attachment 17: Proposed Tariff Structure Statement,* January 2018, pp. 1–2.

120 For example, Essential Energy proposed a time of use demand charge for large business customers. Source: Essential Energy, *2019-24 Tariff Structure Statement*, Proposal, April 2018 pp. 31–33.

121 Australian Competition and Consumer Commission, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry Final Repor*t, June 2018, p. 182.

122 Australian Energy Regulator, *Tariff structure statement South Australia Power Network,* Final Decision, February 2017, p. 74.

123 See for example our analysis of NSW data, Australian Energy Regulator, *Tariff structure statement Ausgrid,* Draft Decision, November 2018, p. 71.

- flat energy charges – are easier for customers to understand, which may lead to greater customer acceptance of demand charges, while maintaining signal for more efficient utilisation including a peak conservation signal through the demand parameter
- time of use energy charges – send stronger conservation signals and will recover a greater proportion of residual costs during peak periods, reducing customers' ability to avoid paying for residual costs through embedded generation and better reflecting customers' demand during system peaks.

We consider that combining seasonal monthly demand charges, with seasonal time of use energy charges is overly complicated. These tariffs may not be well understood by customers. Therefore, we consider, at this stage of tariff reform, the most appropriate demand tariffs are:

- seasonal monthly demand tariffs with flat energy charges where a distributor has a dominant season
- monthly demand tariffs with time of use energy charges where a distributor does not have a dominant season.

We consider demand tariffs are sufficiently cost reflective to be approved as default tariffs.

Distributors should use impact analysis to inform their proposals

When distributors undertake impact analysis to understand the range of impacts that can be expected from the change in tariff strategy, it serves two purposes:

- helping customers to understand the likely impact of the change in network costs on their retail offering, whether it be directly passed through or indirectly through retailers managing these costs across their portfolio
- informing understanding of the need for transitional measures and other complementary measures where impacts are expected to be significant.

SA Power Networks produced an annex summarising the customer impact analysis that informed its proposed tariff strategy.[124] This outlines the impact on different classes of customers, as well as some groupings of customers within classes. SA Power Networks also provided commentary on how this analysis informed the development of its tariff structure statement, such as the decision to reassign residential consumers with interval meters to the default time of use tariff was informed by the expectation that the majority of consumers without PV will benefit and those with PV were unlikely to face an annual increase of more than $100.

Distributors design transitional tariffs to smooth the impact of moving from flat tariffs to more cost reflective tariffs over a longer time-period. Distributors should design

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[124] SA Power Networks, *2020-25 Tariff Structure Statement,* Proposal, January 2019, p. 87.

transitional tariffs to assist vulnerable customers that may need time to adjust to cost reflective pricing. If a distributor decides to offer a transitional tariff, we consider that distributors should offer them on an optional basis. This decision should also be justified by evidence that they consider the impacts of cost reflective tariffs too great in the short-term. Transitional tariffs:

- reduce the efficiency of price signals to customers
- potentially lead to annual changes in price levels for retailers to explain
- are typically more expensive for around half of all customers.

Default tariff assignment should be to cost-reflective tariffs.

Location based pricing has significant advantages

In the current environment, we consider that time of use energy tariffs and demand tariffs best balance cost reflectivity[125] and customers' ability to understand tariffs[126] for the broad range of customers facing default tariff assignment. However, there are ways to make tariffs more cost reflective in the longer term, including:

- Narrow the peak - in 2013, the Productivity Commission found that in NSW peak demand events occur for less than 40 hours per year and are the key driver for network costs.[127]
- Vary by location – distribution networks are made up of many feeder and substation zones. Each zone has its own capacity (or rating), with different load profiles and climates. Therefore, varying tariffs by location can better target the times and locations to signal conservation, indeed in areas with high excess capacity it may be more efficient to encourage usage.

The pricing principles require distributors to comply with all applicable regulatory instruments.[128] We note the government obligation in South Australia to offer the same tariff to all residential and small business customers, regardless of their location falls under this definition and limits SA Power Networks' ability to pursue location based pricing.[129] However, for larger consumers who do not fall under this Order, SA Power Networks proposed to differentiate charging windows for business consumers within the Adelaide city central business district (CBD) and the rest of the network. This is to reflect the different timing of network peaks in the CBD, partly reflecting minimal residential demand and solar generation. This could be taken a step further next time with location calculations of costs applied to these differing windows.

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125 NER, cll. 6.18.5(e)(f) and (g).

126 NER, cl. 6.18.5(i).

127 Productivity Commission, *Electricity Network Regulatory Frameworks,* 9 April 2013, p. 16.

128 NER, cl. 6.18.5(j).

129 South Australian Treasurer, Electricity Act 1996 Section 35B Electricity Pricing Order, 11 October 1999. Cll. 7.3 (f)-(h).

The NER's pricing principles include a principle that distributors must base tariffs on long run marginal cost, including consideration of:

- times of greatest utilisation of the relevant part of the distribution network[130]
- the extent to which costs vary between different locations.[131]

Therefore, if distributors were to propose critical peak pricing or prices that vary by location, there is scope for us to approve a tariff structure of this kind, provided it is consistent with jurisdictional obligations.

The need for innovative tariffs depends on retailers

There exist numerous alternative tariff designs that distributors could propose to improve cost reflectivity while managing customer's ability to understand tariffs. We would consider innovative network tariff solution, just like any other tariff, as part of proposed tariff structure statement in the future. For example, innovative tariffs could involve:

- demand subscription tariffs where customers select the maximum level of demand they will use during peak hours, but face extra charges for exceeding this limit, similar to a mobile phone plan[132]
- peak rebate tariffs where, instead of facing higher tariffs during a critical peak, distributors rewards customers for reducing their demand during times of network congestion.

But in a first-best situation retailers would develop the innovative tariffs based on more standard network tariff structures as one of the tools available to them to reduce the risks of prescribed tariffs, for example:

- Where distributors charge a demand tariff, retailers could develop optional demand subscription tariffs. In this approach, the distributor charges the retailer a demand tariff, and the retailer offers customers demand subscription packages, similar to mobile phone offers. The retailer could charge penalties for greater demand than the package. For example, Amaysim's subscription energy plan is an example of such a structure provided as a retail offering.[133]
- Where distributors charge a critical peak prices, retailers could develop optional peak rebates. In this approach, the distributor charges the retailer a critical peak price, and the retailer charges all customers a premium assuming normal demand during the critical peaks. Customers that reduce their usage during the critical peak

130 NER cl. 6.18.5(f)(2).

131 NER cl. 6.18.5(f)(3).

132 Brown, T., Faruqui, A., Lessem, N., *Electricity Distribution Network Tariffs – Principles and analysis of options prepared for The Victorian Distribution Businesses,* Brattle Group, April 2018, p. 48.

133 Amaysim, *Energy Plans,* accessed 20 August 2019, https://www.amaysim.com.au/help/energy/subscription/about-plans.

would receive discounts, rewards or cash. Powershop's 'Curb Your Power' program is a peak rebate tariff structure provided by a retailer.[134]

We consider there can be strong benefits from innovative tariff designs if they result in greater efficiency, while managing customers' understanding and the impacts of reform. However, partly reflecting the relatively small number of customers assigned to cost reflective network tariffs to date, we have not seen substantial innovation from retailers.

We will be interested to see how SA Power Networks' strategy of aligning residential and small business tariff options to provide clearer, more focused signals to retailers is translated into retail offerings for end users. In particular, retail innovations in response to the impact of the 'solar sponge' period for residential time of use network tariff will offer insights into how network and retail offers can be coordinated to provide a more efficient result to support the long term interest of consumers.

Accumulation meters require anytime charges

Most residential customers still have accumulation meters. As the name suggests, accumulation meters add up/accumulate the amount of electricity used by a consumer during a set period. For households, this is quarterly. They cannot record disaggregated usage within that period, such as half hourly, which is the chief advantage of interval or smart meters. As such, distributors cannot charge these customers any form of cost reflective tariff that requires knowledge of when the customer is using the network.

This requires an anytime charge, where the cost of using electricity does not change based on the time of the day, day of the week or month of the year. But we consider that flat tariffs are superior to inclining block tariffs. The costs of providing network services do not increase in line with the quantity of electricity consumed (in kWh) over a year, but rather when that consumption occurs during peak periods. Inclining block tariffs offer no significant improvement in cost reflectivity, and are more difficult to understand. So we consider distributors should charge customers with accumulation meters flat tariffs.

Large business should face highly cost reflective tariffs

Until this point, we have focused on tariff designs for residential and small business customers. The same NER pricing objective and principles apply to large businesses. However, we consider that we can expect large business customers to understand much more complex network tariff designs. Large business customers will spend a large amount of money each year on electricity. This necessitates large customers investing in understanding components of their retail bills. This means that large business customers should face more cost reflective tariffs than small business and

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134 Powershop, *Curb Your Power,* accessed 3 August 2018, https://www.powershop.com.au/demand-response-curb-your-power/

residential customers. As discussed above, SA Power Networks already offers cost reflective choice to large business customers.

Most of the proposed large business tariffs use similar features to residential charges. However, we have not discussed two charges included in the tariff structure statement proposals so far:

- capacity charges – a form of demand charge that looks at either a customer's maximum demand over a long period, such as 12-months, or on a customer's negotiated maximum capacity
- excess kVAr charges – a charge to customers for the inefficiency of their power factor to compensate the distributor for transporting reactive power.

We encourage distributors to propose more cost reflective tariff designs, such as location based critical peak pricing, on an optional basis for large customers. For example, SA Power Networks' proposal to use the same tariff structure and prices with different charging windows for customers in the CBD and those in the rest of the network. SA Power Networks is also trialling an optional demand tariff to help address constraints in the Riverland area.[135] These customers should be able to understand these network tariffs and may find such tariffs beneficial in managing their retail bills.

Most distributors provide individually calculated tariffs for some high voltage and sub-transmission customers. We consider distributors should set out, in their tariff structure statements, how they will calculate those individually calculated tariffs and the criteria for customers to access these tariffs. This additional transparency provides:

- existing and potential high voltage and sub-transmission customers greater certainty in their tariffs
- protection for other customers from the potential for negotiated individually calculated tariff customers being systematically lower than the published large business charges.

Distributors should provide us with how they have calculated individual tariffs as part of their annual pricing proposals, so that we can confirm they are consistent with the methodology in the tariff structure statements.

B.4 Is consistency important between distributors?

Under the NER there is no explicit requirement for consistency between distributors. However, the NER have a consistent set of pricing principles. To comply successfully with all the pricing principles there may need to be some commonality for a variety of reasons:

- Cost reflectivity – while the cost drivers for most distribution businesses may differ, such as the substantially higher penetration of solar in South Australia and

135 SA Power Networks, *2020-25 Tariff Structure Statement,* Proposal, January 2019, p. 49.

Queensland, the principles to be applied are generally the same and so may generate similar tariffs.

- Ability of customers to understand electricity charges - most customers only spend a small proportion of their time considering how their retailer calculates their electricity bill. Having consistent tariff designs, if that flows through to retail tariff design, may make it easier for Governments, distributors and retailers to help customers understand their bills.

In the three sections above, the NER and the current state of tariff reform, have led us to propose a baseline set of tariff designs and assignment policies that distributors should aim to achieve (or explain any deviations).

We consider that if distributors apply our positions, outlined above, in their tariff structure statements, distributors will achieve a high level of consistency. This is not the aim of the sections above, but a natural consequence of it.

Overall, we consider consistency between distributors is a positive to the extent that it makes tariffs cost reflective and makes it easier for customers to understand this component of their retail electricity bill.

C Long run marginal cost

In this appendix, we set out our framework for assessing the method(s) a distributor used to derive its long run marginal cost (LRMC) estimates for its proposed tariff structure statement.

C.1 Background

When tariffs accurately reflect the marginal, or forward-looking, cost of increasing (or decreasing) demand, consumers can make informed choices about their electricity usage. Under such tariffs, customers would increase their use of the network only when they value it more than the costs. This in turn signals to distributors to invest in additional capacity to the extent that customers value it.[136]

LRMC is equivalent to such forward looking costs—more specifically, as measured over a period of time sufficient for all factors of production to be varied.[137] LRMC could also be described as a distributor's forward looking costs that are responsive to changes in electricity demand. This could include investment in additional network capacity to service growing peak demand.[138] As we discuss below, this could also include replacement of fixed assets at the end of their economic life where changes in demand is a consideration.

The estimation of LRMC involves three key steps, which are to:

- choose the overall approaches or estimation method(s)
- define what costs are considered 'marginal' vs. what costs are considered 'residual'
- define what timeframe is considered the 'long run'.

As we discuss below, this provides the framework for our approach to assessing a distributor's LRMC estimation methods.

C.2 Note on LRMC, residual costs and approach to tariff setting

The rules require network tariffs to be based on LRMC.[139] However, not all of a distributor's costs are forward looking and responsive to changes in electricity demand. For example, distributors may need to replace network assets when they are old and/or have deteriorating condition. Hence, if network tariffs only reflected LRMC, distributors would not recover all their costs. Costs not covered by a distributor's LRMC are called 'residual costs'. The rules require network tariffs to recover residual costs in

136 Alternatively, customers may reduce their use of the network if the benefit they derive is less than the costs. This in turn signals to distributors the potential to reduce capacity in the network.

137 NER, chapter 10 Glossary.

138 Peak demand can be due to increased economic activity or seasonal factors such spikes in air-conditioner use on hot summer evenings.

139 NER, cl. 6.18.5(f).

a way that minimises distortions to the price signals for efficient usage that would result from tariffs reflecting only LRMC.[140] This appendix sets out our assessment framework. We also outline some principles in our assessment of the approach the distributor used to set tariff levels in pricing proposals—including how it considered LRMC estimates to set such tariffs and how it allocates residual costs.[141]

C.3 Assessment approach

This is the second tariff structure statement round for the electricity distribution businesses undergoing a distribution determination.[142] In this round, we are assessing the extent to which a distributor made improvements to its methods for estimating LRMC compared to the first tariff structure statement round. In particular, we assessed whether a distributor:

- investigated the inclusion of replacement capex (repex) in their LRMC calculations[143]
- used a minimum of 10 years of forecast data in the calculation of LRMC[144]
- continued to refine their methods for estimating LRMC so their tariffs better reflect efficient costs.[145]

These are the improvements we encouraged distributors to explore in our final decisions for the first tariff structure statement round, which we completed in 2016–17. The above criteria establish our approach for assessing LRMC estimation methods in this second tariff structure statement round.

Importantly, we consider these criteria allow us to assess the extent to which a distributor has progressed tariff reform as envisioned in the rules, particularly the requirement that a distributor's method(s) of calculating LRMC has regard to:[146]

- the costs and benefits of implementing the method(s) of calculating LRMC
- the additional costs of meeting demand from customers at times of greatest utilisation of the relevant part of the distribution network
- the location of customers and the extent to which costs vary between different locations in the distribution network.[147]

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140 NER, cl. 6.18.5(g)(3).

141 NER, cl. 6.18.1A(a)(5).

142 The exception is Power and Water Corporation, which was not required to submit a TSS in the first round. However, our final decisions from the first TSS round have been available to Power and Water Corporation to guide in developing its first TSS.

143 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, pp. 92–94.

144 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 94.

145 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 90.

146 NER, cl. 6.18.5(f).

Broadly speaking, we would consider a distributor's LRMC estimation method contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective:

- made the improvements discussed above to their LRMC estimation methods.
- explained its proposed approach within the context of the current stage of tariff reform and the Rules.

We discuss each of our criteria in more detail below.

C.4 Inclusion of repex in LRMC estimates

In our final decision for the first tariff structure statement round, we encouraged distributors to investigate including repex in their LRMC estimates.

Assessment criteria:

We consider whether repex (or any other types of capex) that a distributor includes in its LRMC estimates should meet the definition of 'marginal cost'—that is, the cost of an incremental change in demand.

Where a distributor has not included repex in their LRMC estimates, it must demonstrate why it does not have any forecast repex that can be considered as a 'marginal cost'.

In our final decision for the first tariff structure statement round, we noted the rules define LRMC as the cost of an incremental change in demand over a period of time in which all factors of production can be varied.[148] In the long run, the level of capacity in a distribution network is a variable factor of production. When assets come to the end of their useful life, distributors have a choice of maintaining their current level of capacity, increasing capacity or decreasing capacity, depending on demand and use of the network. Distributors should not adopt a default position of maintaining existing capacity levels, especially where existing networks have spare capacity and where there are changing patterns of use. We considered LRMC estimates should include replacement capital expenditure and associated operating expenditure. This would promote network capacity in the long run at levels consumers' value.[149]

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[147] As we discuss in sections 0 and 0, we consider the location-based aspect of measuring LRMC is not a primary consideration at this stage of tariff reform, although it could become a more prominent consideration in future TSS rounds.

[148] NER, chapter 10—Glossary.

[149] For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, pp. 92–93.

We also noted not all types of repex should be included in LRMC estimates.[150] Marginal cost refers to the cost of an incremental change in demand.[151] Not all repex is associated with an incremental change in demand. For example, we consider repex driven purely by asset condition would not be included in LRMC estimates.

If a distributor includes repex that is consistent with the definition of marginal cost, the next step is assessing whether it has incorporated such expenditure appropriately into its LRMC estimation method. We assess a distributor's incorporation of repex into its estimation method on a case by case basis. This is because we acknowledge LRMC estimates have not traditionally included repex in the context of Australian network regulation. We consider this second tariff structure statement round provides distributors (and other stakeholders, including the AER) with the opportunity to explore and test this aspect of LRMC estimation. Indeed, distributors have proposed several viable methods for incorporating repex into their LRMC estimates in this second tariff structure statement round.[152]

C.5 Definition of 'long run'

In our final decision for the first tariff structure statement round, we noted distributors have typically used timeframes of between 10 and 40 years to estimate long run marginal costs. We considered this timeframe captures the essence of 'long run'.[153]

Assessment criteria:

We consider distributors should use a minimum forecast horizon of ten years as inputs into their estimation methods to adequately capture the 'long run'. This is consistent with what we said in approving the first tariff structure statement round.

The rules define long run marginal costs as the cost of an incremental change in demand over a period of time in which all factors of production can be varied.[154]

In the long run, the level of capacity in a distribution network is variable. Accordingly, the 'long run' would match the life of the assets. Some distribution network assets have very long lives (in excess of 60 years). However, it would be impractical to produce

150 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, pp. 92–93.

151 NER, chapter 10 (definition of long run marginal cost).

152 See attachment 19 of our respective draft decisions for those distributors with distribution determinations for the 2019–24 regulatory control period (Evoenergy, TasNetworks, Power and Water, Ausgrid, Endeavour Energy and Essential Energy).

153 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 94.

154 NER, chapter 10.

accurate forecasts over such a long horizon. The longer the estimation period, the more difficult it becomes to estimate and forecast long run costs.[155]

We think there is no ideal, or correct, timescale on which to base these estimates and we accept a range of timeframes would be compliant with the rules.

However, the timescale must be long enough to allow a significant number of factors of production to change—and a key factor of production is the level of capacity in the network. We consider a minimum forecast horizon of ten years captures the essence of 'long run'.

C.6 LRMC estimation methods

This section discusses our approach to assessing the extent to which distributors have made improvements to the LRMC estimations methods. This entails assessing whether the distributors:

- made improvements to their application of the Average Incremental Cost approach;[156] and/or
- explored the use of other estimation methods, such as the Turvey approach.

Assessment criteria:

In this second tariff structure statement round, we take a practical approach to assessing whether a distributor has made sufficient improvements to its LRMC estimation method(s).

We will be mindful of the costs and benefits to industry of using more accurate estimation methods in this early phase of tariff reform and will assess each proposal on a case by case basis.

As a base, we would consider a distributor has adequately improved its estimation method if it has properly incorporated repex. We consider doing so demonstrates improved application of an LRMC estimation compared to the first tariff structure statement round.

In the first tariff structure statement round, all distributors in the NEM used the Average Incremental Cost approach to estimate LRMC, which we accepted. We encouraged distributors to continue improving their estimation methods so their tariffs better reflect efficient costs. This may entail modifying the Average Incremental Cost approach, or

155 For example, assumptions about future growth at zone substation and/or terminal stations become more difficult to forecast with a longer planning horizon.

156 All distributors used the Average Incremental Cost approach to estimate LRMC in the first TSS round.

utilising more sophisticated approaches, such as the Turvey approach if they consider it appropriate.[157]

A general perception is the Average Incremental Cost approach is less costly to implement than the Turvey approach, but produces less accurate estimates of LRMC.

Conversely, the Turvey approach is more costly to implement than the Average Incremental Cost approach, but is perceived or is in principle capable of producing estimates that better represent LRMC.[158]

Of course, distributors are not limited to using the Average Incremental Cost approach or the Turvey approach. Indeed, there are several versions and interpretations of the aforementioned approaches.[159]

A key question in our assessment (and for distributors in making their tariff structure statement) is whether the benefits of more accurate estimates of LRMC outweigh the costs of deriving them.[160] This cost-benefit equation will depend on the circumstance of each business.

We therefore assess the extent to which a distributor has made improvements to its estimation method on a case by case basis. The aspects of a distributor's circumstance that are relevant for our assessment include:

- **Penetration of interval meters**—there is currently low penetration of interval or more advanced (smart) meters in most jurisdictions. This implies distributors can assign a relatively low proportion of customers to cost reflective tariffs (which should signal LRMC).[161] The principal benefit of cost reflective pricing is that customers' use of the network reflects the value they derive from such use. This would then provide the signal to distributors to efficiently invest in the network.[162]

  However, this link between cost reflective pricing, customer usage and network investment would require a 'critical mass' of customers that can receive LRMC signals and then respond to such signals.

- **Postage stamp pricing**— Distributors charge customers the same tariffs across their networks (except for a small number of bespoke tariffs offered to the distributor's largest customers). However, the marginal costs of distribution vary by

157 For example, see AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, p. 90.

158 For a discussion on the relative merits of these approaches, see NERA, *Economic Concepts for Pricing Electricity Network Services: A Report for the Australian Energy Market Commission*, 21 July 2014, pp. 14–16.

159 For a discussion, see Marsden Jacob Associates, *Estimation of long run marginal cost (LRMC): A report prepared by Marsden Jacob Associates for the Queensland Competition Authority*, 3 November 2004.

160 NER, cl. 6.18.5(f)(1).

161 Such as demand charges or time of use charges.

162 A misconception is that cost reflective pricing will automatically lead to lower network investment and ultimately lower prices. Cost reflective pricing could lead to (efficient) higher investment and prices if customers value additional use of the network.

location, based on the rate of change in demand and level of congestion within the substation or feeder zone (as well as temporal factors).[163] Accordingly, basing tariffs on an estimate of average LRMC or a part of the network's LRMC sends inefficient price signals to most, if not all, customers.[164]

Postage stamp pricing is less costly and simpler to administer for distributors and retailers than locational pricing.[165] It is also arguably more equitable for many end customers. It is therefore unclear the extent to which the industry would, or could, move away from postage stamp pricing in future tariff structure statements. We are not expecting any substantive move by distributors to move towards location-based pricing in this round of tariff structure statements.

Note on the transition to marginal cost pricing

For many distributors, the levels of their cost reflective tariffs differ from their LRMC estimates. This is a legacy of previous practices, when the requirement to consider LRMC was much lower than the current version of the rules.[166] Distributors are transitioning their tariffs toward their LRMC estimates having regard to customer impacts.[167]

Broadly, there are two transitions to marginal cost pricing: 'from above' where the levels of their cost reflective charging parameters[168] are higher than their LRMC estimates; or 'from below' where their cost reflective charging parameters are lower than their LRMC estimates.

In the former, their cost reflective charging parameter contains residual costs on top of the signal of future costs. The transition towards the LRMC estimates, therefore, involves re-allocating residual costs to other tariff parameters such as the fixed charge or a non-time-varying consumption charge (if present). The re-allocation should ensure there is minimal distortion to the efficient price signal.[169]

In the latter, the cost reflective charging parameter currently sends a muted signal of

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163 The NER recognises the potential differences in LRMC between different locations in the network—NER, cl. 6.18.5(f)(3).

164 Endeavour Energy developed separate LRMC estimates for substation zones that have growing demand and substation zones with falling demand. Endeavour Energy proposed to base tariffs on the LRMC for substation zones that have growing demand.

165 There are several degrees to locational pricing. At a higher level, locational pricing could equate to pricing by "regions" of a network, where a region may encompass zone substations that are inter-related by customer or growth characteristics, for example. At a lower level, locational pricing could equate to pricing by zone substation or even by feeder.

166 Prior to the AEMC's rule change in 2014, the rules stated distributors "must take into account" LRMC when setting prices (NER version 62, cl. 6.18.5(b)(1)). The current rules state tariffs "must be based" on LRMC (NER version 111, cl. 6.18.5(f)).

167 NER, cl. 6.18.5(h).

168 Generally, these are the peak charge of a time of use tariff, or the demand charge of a demand tariff.

169 NER, cl. 6.18.5(g)(3).

future costs. The distributor would therefore increase the cost reflective charging parameter towards the LRMC estimate while having regard to customer impact.[170]

Another important feature of the transition to the LRMC estimate is its translation into the relevant cost reflective charging parameter. For example, many distributors derive an LRMC estimate on $/MW basis, but offer a time of use tariffs with a peak charge in $/MWh. In such cases, the distributor should use an appropriate conversion factor.

Equally important is the application of the LRMC estimate to the appropriate charging window. Under fully locational and dynamic tariffs, the level of the cost reflective charging parameter would equal the LRMC estimate because the signal of future cost matches the timing of network congestion.

In the absence of locational dynamic tariffs, charging windows—especially, the peak window—designate the times in which there is the highest probability of congestion. The LRMC estimate would exceed the level of cost reflective charging parameters under such a tariff regime. The extent of this difference depends on several factors and increases when:

- peak charging windows incorporate a greater number of hours—a wider peak window increases the likelihood that it captures the actual times of network congestion. On the other hand, it entails 'spreading' the LRMC estimate over a greater number of intervals.
- there is more spare capacity in the network—the presence of spare capacity reduces the probability of congestion at any time (including peak hours) and at any location in the network under postage stamp pricing.

We encourage distributors to describe in detail how they translate their LRMC estimates into their cost reflective charging parameters, including all assumptions and inputs, having regard to the factors discussed above. This would increase transparency in the tariff setting process. For example, it would more clearly delineate between LRMC signals and residual costs, and so assist in the transparent allocation of the latter to the relevant charging parameters. It would also provide suggestions for areas of improvement in estimating LRMC in subsequent tariff structure statements.

C.7 Future directions

As with the first tariff structure statement round, we encourage distributors to continue to refine their methods for estimating LRMC in the third tariff structure statement round.

This may mean further refining the Average Incremental Cost method, or adopting more sophisticated estimation methods, such as the Turvey method, if distributors consider it can be justified on cost-benefit grounds. Distributors may also adopt multiple estimation methods, as we discuss below.

170 NER, cl. 6.18.5.

We further encourage distributors to continue exploring the types of repex—and other expenditure types—that can properly be considered as 'marginal cost' and hence included in LRMC estimates. As a corollary, we also encourage businesses to continue exploring how they incorporate repex and other expenditure types into their estimation methods. As we discussed above, distributors proposed alternative methods for incorporating repex into their LRMC estimates in this second tariff structure statement round. We consider the industry can use the learnings from this second tariff structure statement round to potentially consolidate the methods for including repex in LRMC estimates for subsequent tariff structure statement rounds.

As required by the NER, we will be mindful of the costs and benefits of improving LRMC estimation methods in our assessment of future tariff structure statements.[171] In the sections above, we acknowledged several factors in the current stage of tariff reform that may limit the benefits of using more sophisticated estimation methods such as the Turvey method.

However, we are also mindful of the changes occurring in the energy industry that could remove, or at least lower, such barriers in future tariff structure statement rounds. Factors to consider for the third tariff structure statement round include ongoing progress regarding:

- **Penetration of interval or more advanced meters**—as discussed in the sections above, there is currently relatively low penetration of interval meters in most jurisdictions. This limits the extent to which distributors can send LRMC signals to customers.

  However, the AEMC's metering rule change took effect from 1 December 2017. This should promote increasing penetration of interval meters in the NEM.[172] Distributors should monitor the rate of interval meter penetration and consider the extent to which it can accelerate tariff reform in the third tariff structure statement round. This includes considering the benefits to distributors and its customers of deriving (and signalling) more accurate estimates of LRMC.

- **Postage stamp pricing**—as we discussed above, postage stamp pricing applies to a large majority of distributors' customers for administrative and equity reasons.

  The higher costs of more accurate methods to estimation LRMC may be justifiable where a distributor proposes tariffs that send locational signals of congestion. In future tariff structure statement rounds, a distributor may experiment with using such methods if it proposes to trial tariffs in particular areas of its network, for

[171] NER, cl. 6.18.5(f)(1).

[172] The AEMC metering Rules do not apply in the Northern Territory. We consider Power and Water's metering proposal in AER, *Draft Decision: Power and Water Corporation Distribution Determination 2019 to 2024: Attachment 16: Alternative control services*, September 2018.

example.[173]

Also, having regard to location when estimating LRMC does not require a distributor to actually apply location-based pricing. In this second tariff structure statement round, for example, Endeavour Energy produced two separate LRMC estimates: one for areas of stable or decreasing demand, and another for areas of increasing demand. However, Endeavour Energy still proposed to apply postage stamp pricing for the 2019–24 regulatory control period.[174]

Having LRMC estimates by location also has benefits beyond pure tariff setting. This is because it would help to identify locations where the benefits of demand management outweigh the costs. Location-based LRMC estimates would assist in the assessment of project costs with and without demand management in constrained areas of the network.

We consider this is consistent with the rules requirement that LRMC estimates have regard to the extent to which costs differ between locations (without actually applying locational pricing).[175] It also provided Endeavour Energy with further information regarding the appropriate LRMC estimate on which to base its prices.[176]

On this last point, we note distributors are not restricted to a single method when estimating LRMC. Just as distributors utilise a combination of different methods to derive their expenditure forecasts, they can use a combination of estimation methods to derive LRMC estimates.

Distributors may use different estimation methods to account for different types of marginal costs. Ausgrid did so in this second tariff structure statement round to measure the different contributions to LRMC of augmentation capex and replacement capex.[177] Distributors may use different estimation methods, where one method acts as the 'primary' estimation method, while a second method acts as a 'sanity check'. Or, distributors may use different estimation methods to derive a range for LRMC, rather than point estimates, as Ausgrid did in this second tariff structure statement round.[178]

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173 We note distributors may also send temporal and/or location-based signals of network costs through non-tariff means, such as rebates or demand management initiatives.

174 Endeavour Energy based its prices on the latter estimates because Endeavour Energy considered the impact of inefficient signals in growing areas is greater than in areas of declining demand under postage stamp pricing. See Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 87.

175 NER, cl. 6.18.5(f)(3).

176 NER, cl. 6.18.5(f).

177 Ausgrid, *Attachment 10.04 – Deloitte – LRMC Methodology Report*, December 2017, pp. 11–16.

178 The Independent Pricing and Regulatory Tribunal of NSW did similarly for Sydney Water Corporation: IPART, *Final Report: Review of prices for Sydney Water Corporation from 1 July 2016 to 30 June 2020*, June 2016, pp. 288–289.

On a final note, we propose consulting with distributors more regularly outside of the distribution determination process on progressing LRMC estimation methods. This is consistent with a suggestion from Energy Networks Australia in the first tariff structure statement round who stated the industry should devote resources to improve the estimation of LRMC.[179] We consider progressing estimation methods for LRMC is an area that could benefit from collaboration and knowledge-sharing between distributors and other stakeholders. This could spread the costs of developing more accurate estimation methods, while maximising the benefits of efficient price signals.

[179] ENA, *Submission: Australian Energy Regulator draft decision on tariff structure statement proposals*, 7 October 2016, p. 3.

D Assigning retail customers to tariff classes

This appendix sets out our draft determination on the policies and procedures governing assignment or reassignment of SA Power Networks' retail customers for direct control services.[180] Our draft determination is based on SA Power Networks' proposed procedures for assigning and reassigning retail customers to tariff classes.

D.1 Procedures for assigning and reassigning retail customers to tariff classes

1. The procedure outlined in this section applies to direct control services.

Assignment of existing customers to tariff classes at the commencement of the regulatory control period

2. SA Power Networks' customers will be taken to be assigned to the tariff class which was charging that retail customer immediately prior to 1 July 2020, if:
    - They were a customer prior to 1 July 2020, and
    - Continue to be a customer as at 1 July 2020.

Principles for assignment or reassignment of customers to a tariff class during the regulatory control period

3. SA Power Networks will use the following characteristics to determine the appropriate tariff class:
    - Nature and extent of usage
    - Nature of connection to the network
    - Nature of metering technology – whether there is remotely-read interval metering.
4. SA Power Networks will also ensure:
    - Customers with similar connection and usage profiles are treated equally
    - Customers with micro-generation facilities are not treated less favourably than others with similar load profiles without such facilities. To this end net customer demand is used to determine nature and extent of the customers' usage.
5. In addition, when assigning or reassigning a retail customer to a tariff class, SA Power Networks must take into account whether:
    - Retail customers with similar connection and usage profiles are treated equally

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180 NER, cl. 6.12.1(17).

- Retail customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities
- The national pricing objective and the distribution pricing principles which direct that tariffs charged by a distributor for direct control services should reflect the distributor's efficient costs of providing these services to the customer.

Assignment of new customers to a tariff class during the regulatory control period

6. When a customer or their retailer lodges a connection application, SA Power Networks will use the above principles to assign customers to a tariff class.
7. Residential customers will be assigned to the default time of use tariff, unless they have a legacy Type 6 (accumulation) meter which means they will be assigned to the single rate tariff.
8. Business customers will be assigned based on their connection characteristics, i.e. whether they are connected to the sub-transmission, zone substation, 11 kV, or LV part of the network. For customers in the LV network, assignment will also be affected by the magnitude of their annual consumption (> or < 160 MWh pa) and, to a lesser extent, their metering technology. This is because LV businesses with Type 6 meters will not have the technology required to support more than the single or two rate tariff.

Reassignment of existing customers to another existing or a new tariff class during the regulatory control period

9. Reassignment can be triggered by a change in the customer's load and/or connection characteristics. It should be noted that a change in the existing account holder's name will not lead to reassignment.
10. Changes in the load characteristics have to be sufficient enough that it is no longer appropriate for the customer to be assigned to their current tariff class and/or it is no longer sufficiently similar to the characteristics of others within this class. This is particularly the case for business customers.
11. Changes in connection characteristics can occur when the customer alters their supply by changing the available capacity, converting from single phase to three phase power, or installing an inverter to enable both import to and export from the network. Each of these alterations will require a new meter be installed which must be an interval meter.

Reassignment to another tariff within the existing tariff class

12. From July 2020, there will be the following reassignments to cost reflective tariffs within tariff classes:
    - all residential customers with a Type 4 or 5 (interval) meter will be assigned to the default time of use tariff
    - all residential OPCL customers with a Type 4 (remotely read, interval) meter will be assigned to the default OPCL time of use tariff

- all small business with a Type 4 or Type 5 meter will be assigned to the small business time of rate and those with demand exceeding 70 kVA will also face an anytime demand tariff
- all residential and small business customers replacing ageing meters with interval meters will be assigned to the appropriate default cost reflective tariff.

13. Customers will be provided with a choice between the default cost reflective tariff and an alternative for each tariff class. The only tariff class not provided with this option is LV Business < 160 MWh pa but > 70 kVA. For residential consumers and LV Business < 160 MWh pa and < 70 kVA, there is the option to change from the time of use tariff to a tariff with lower time of use rates and a demand charge. Other business customers will be able to choose between actual and agreed demand tariffs.

Notifications

14. SA Power Networks will notify the customer's retailer in writing of the tariff class to which the customer will be assigned or reassigned prior to the network charge assignment or reassignment occurring. This notice will inform the customer's retailer of the following:
    - The customer's retailer may request further information and may object to the proposed re-assignment
    - SA Power Networks has a written document outlining internal procedures for reviewing objections. To this end SA Power Networks has made "Manual 18, Network Tariff Manual" publically available on its website
    - If the objection is not resolved to the satisfaction of the customers' retailer under SA Power Networks' internal review system within a reasonable timeframe, the customers' retailer is entitled to escalate the matter to the Energy and Water Ombudsman of South Australia (EWoSA) or like officer, to the extent that resolution of such disputes is within their jurisdiction
    - If the objection is not resolved to the satisfaction of the customer's retailer under SA Power Networks' internal review system and EWoSA or like officer, then the customer or its retailer is entitled to seek a decision of the AER via the dispute resolution process available under Part 10 of the National Electricity Law (NEL).

15. If SA Power Networks received a request for further information from a customer's retailer in response to a notification of assignment or reassignment, it must provide such information within a reasonable timeframe. SA Power Networks is not required to provide information it reasonably claims is confidential. But if the customer's retailer disagrees with the confidentiality claim, the retailer may resort to the dispute resolution procedures outlined in the notice.

Objections

16. SA Power Networks must reconsider the proposed assignment or re-assignment if a customer's retailer objects to SA Power Networks about the proposed

assignment of re-assignment. In doing so, SA Power Networks must consider its principles for assignment or re-assignment to a tariff class and notify the customer's retailer of its decision and the reasons for that decision.

17. If a relevant body upholds the customer's retailer's objection to tariff assignment or re-assignment, then any adjustments which need to be made to tariffs will be done by SA Power Networks as part of the next annual review of prices.