FINAL DECISION

Tariff structure statements

Energex and Ergon Energy

February 2017

AUSTRALIAN ENERGY REGULATOR

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Version	Date	Pages
1	February 2017	105

Contents

Glossary

Term	Interpretation
Apparent power	See kVA
CoAG Energy Council	The Council of Australian Governments Energy Council, the policy making council for the electricity industry, comprised of federal and state (jurisdictional) governments.
Consumption tariff	A tariff based on energy consumed (measured in kWh) during a billing cycle. Examples of consumption tariffs are flat tariffs, inclining block tariffs and declining block tariffs.
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 (measured in kW or kVA) used within a specified time (e.g. peak charging window) and which is reset after a specific period (e.g. at the end of a month or billing cycle).
Demand tariff	A form of tariff that incorporates a demand charge component.
Excess reactive power charge (Excess kVAr)	A tariff component for Ergon Energy based on the amount of excess reactive power above the customer's permissible quantity. A customer's authorised demand and compliant power factor is used to calculate its permissible reactive power.
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 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 and smart meters	In this decision, used to refer to meters capable of measuring electricity usage in specific time intervals and enabling tariffs that can vary by time of day.
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.
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.
kVAr	Also called Reactive Power. In electricity transmission and distribution, kVAr is a unit by which reactive power is expressed in an alternating current power system. Reactive power exists when the current and voltage are not in phase.
LRMC	Long Run Marginal Cost. Defined in the National Electricity Rules as follows: *"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

Term	Interpretation
	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".*
NER	National Electricity Rules
Power factor	The power factor is the ratio of real power to apparent power (kW divided by kVA).
Tariff	A tariff is levied on a customer in return for use of an electricity network. A single tariff may comprise one or more separate charges, or components.
Tariff structure	Tariff structure is the shape, form or design of a tariff, including its different components (charges) and how they may interact.
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.
Time of use tariff	A tariff incorporating usage charges with varying levels applicable at different times of the day or week. A time-of-use 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.

Our final decision

Our final decision is to approve Energex's revised tariff structure statement submitted to us on 4 October 2016, subject to clarifications made to the statement.

Our final decision is to approve Ergon Energy's revised tariff structure statement submitted to us on 4 October 2016, subject to clarifications made to the statement.

We approve Energex and Ergon Energy's tariff structure statements. We are satisfied that the tariff structure statements comply with the distribution pricing principles and other applicable requirements of the Rules.

We approve the move to include opt-in demand tariffs for residential, small and medium business customers set out in both Energex and Ergon Energy's revised tariff structure statements. We are satisfied inclusion of these network tariffs in the distributors' tariff structure statements contribute to the achievement of compliance with the distribution pricing principles.

Energex and Ergon Energy have introduced new cost reflective residential and business tariffs and this continues a theme that they commenced a couple of years ago. Customers will now have the choice of flat tariffs, inclining block tariffs and opt-in time of use energy and opt-in time of use demand charges. This will provide considerable choice for retailers as they design tariffs that package networks tariffs into retail pricing plans that suit end use customers.

Submissions were generally supportive of cost reflective tariffs and in favour of the opt-in tariff approach adopted by the Queensland distributors. However there were concerns about how the customer impacts would be managed. Implementation and transition were seen as important. Canegrowers were concerned about the length of business charging windows for irrigators and the derivation of long run marginal cost calculations. Retailers have been supportive of more cost reflective tariffs but sought simplicity to ensure customers could understand them, while minimising bill impacts where possible. Customer groups wanted the networks to track the effectiveness of cost reflective tariffs over time to understand how customers respond to them, and to make necessary adjustments over time. The Clean Energy Council also advocated this. They considered the integration of effective (including automation of) demand management with pricing would play a key role in the success and adoption of cost reflective tariffs. Canegrowers were concerned about the length of Ergon Energy's charging windows for small and medium sized business customers. They also considered that Ergon Energy did not have significant future demand pressures affecting its network and so long run marginal costs should be a relatively small proportion of network charges.

Tariff reform is important for ensuring the grid is used effectivity in the future. There is no common view about how cost reflective prices should look, or what the ideal cost reflective pricing structure should look like. However, the National Electricity Rules mandate that network tariffs are to be set on the basis of long run marginal costs and meet the pricing principles in clause 6.18.5 of the Rules.

We consider that demand tariffs are more cost reflective compared to flat tariffs or block tariffs that are based only on consumption. Demand tariffs tend to more closely resemble the cost of customers' decisions to utilise the distribution network at times of peak demand or congestion on the network than consumption-based tariffs. Demand tariffs encourage customers to reduce or move their consumption to times when the network is less peaky or congested. Reducing consumption during times of peak network demand or congestion should mean less network investment is necessary to provide reliable electricity supply during those peak times. In the long run, reduced network investment will mean lower prices for all customers than would otherwise be the case. Nevertheless distributors should still consider other forms of cost reflective pricing which target areas of network congestion more closely in future tariff structure statements.

In our draft decision, we were satisfied that demand tariffs met the achievement of compliance with the distribution pricing principles. However, we requested Energex consider charging windows for business customers to ensure that the length of the peak period was matched to the overall demand profile. Some customers were concerned that the peak period window might have been too long, and not reflective of the demands placed upon the network. Energex's revised tariff structure included analysis of the maximum demands occurring on its network in summer months which showed that the proposed peak period window covered times when maximum demand was rising on its network. We have accepted their analysis and approve the charging windows as proposed.

We have also looked at the peak charging windows applicable Ergon Energy's tariffs. There were diverse views about charging windows for the Queensland distributors, particularly in relation to business customers. This was most notable from the irrigation sector, who was concerned at the length of Ergon Energy's proposed peak charging windows.[1] Our draft decision requested Ergon Energy to look at the business tariffs that affect the irrigation customers to determine if a different tariff or charging window should be offered to them. Clarity about the length of the charging windows was also sought. There were numerous submissions from Canegrowers and their consultant, along with many responses from Ergon Energy in reply. Ultimately, we have approved

1 Canegrowers – Sapere – *Errors in AER draft decision on Ergon Energy 2016 Tariff Structure Statement,* 22 November 2016, pp. 23-27.

Ergon Energy's proposed seasonal time of use energy and seasonal time of use demand charges and the charging windows that accompany them. We consider these contribute to achievement of compliance with the distribution pricing principles.

Residential customers

Energex

We approve Energex's legacy tariffs and opt-in demand based tariffs for residential customers. We are satisfied that these tariffs contribute to achievement of compliance with the distribution pricing principles.

Customers can opt-in to these tariffs and then choose to opt back out if they wish. The default tariff for existing residential and new residential customers is the residential flat tariff.

Energex has traditionally relied on retailers to advise it of a customer's particular circumstances. If a customer is already on a network demand tariff, they will remain on it unless the retailer advises Energex of the customer's preference to opt out. Likewise, a customer on the flat tariff will remain on it unless they (via their retailer) decide to opt-in to the demand tariff.

Stakeholders have been supportive of the proposed tariffs and the move to cost reflective pricing more generally. Table 1: sets out our decision.

Ergon Energy

We approve Ergon Energy's legacy tariffs and opt-in demand based tariffs for residential customers. We are satisfied that these tariffs contribute to achievement of compliance with the distribution pricing principles. See Table 2 for an outline of the Ergon Energy final decision.

The inclining block tariff is the default tariff for existing residential and small-medium business customers. Customers can opt-in to the seasonal time varying and seasonal demand tariffs. They can then opt-out to the default inclining block tariff if they wish.

In 2017–18, for a new customer the inclining block tariff is the default tariff. They may opt-in to the time varying and demand tariffs. From 2018–19 new customers will be on the demand tariff by default but can opt-in to the inclining block tariff or the time varying tariff. This applies to residential and business customers.

Views about the types of cost reflective tariffs that should be introduced have varied by stakeholders.

Canegrowers did not agree that the new time of use energy charge or the time of use demand charge were structured appropriately. They considered that the peak charging windows should be reduced. They were also concerned that the tariff levels were set too high for the legacy inclining block tariff. These views are addressed in Chapter 8 and Chapter 5.2, respectively.

Table 1: Energex, residential customers

Our draft decision	Energex revised proposal	Our final decision
We approved Energex's proposed opt-in time of use and demand based tariffs for residential customers. We approved providing mandatory assignment commencing 1 December 2017 and the alteration requires a new meter.	No change from the initial proposal.	No change from the draft decision.
We approved Energex's proposed charging windows for peak, shoulder and off-peak for residential customers on time of use and demand tariffs. Peak: 4pm to 8pm weekdays Shoulder: 7am to 4pm and 8pm to 10pm weekdays, 7am to 10pm weekends Off-peak: 10pm to 7am every day	No change from the initial proposal.	No change from the draft decision.
We approved Energex's proposed default tariff being the residential flat usage tariff, regardless of meter type, comprising of a fixed charge and a non-varying usage charge.	No change from the initial proposal.	No change from the draft decision.
We approved Energex's proposed method for measuring a customer's peak demand as the highest use recorded in a 30 minute period that falls within its peak charging window during the month. As a transitional measure the demand charge will be capped at 5kW for the first 12 months that a customer is on the demand tariff. We accept this basis of charging in	No change from the initial proposal. Energex confirmed the cap of 5kW for the first 12 months.	No change from the draft decision.

the initial phase of network tariff reform as we consider the approach adequately manages customer impacts.		
We approved the secondary tariffs: super economy, economy, smart control, unmetered and Solar FiT. These secondary tariffs reduce customer bills in return for Energex remotely controlling customer appliances to alleviate demand pressures.	No change from the initial proposal.	No change from the draft decision.

Table 2: Ergon Energy, residential customers

Our draft decision	Ergon Energy revised proposal	Our final decision
We approved Ergon Energy's opt-in time of use and demand based tariffs for residential customers. We approved providing mandatory assignment commencing 1 December 2017 and the alteration requires a new meter.	No change from the initial proposal.	No change from the draft decision.
We approved Ergon Energy's proposed charging windows for peak and off-peak for residential customers. Peak: 3pm to 9.30pm every day (summer only for time of use tariff) Off-peak: All other times	No change from the initial proposal.	No change from the draft decision.
We approved Ergon Energy's proposed default tariff being the inclining block tariff, regardless of meter type, comprising of a fixed charge and a varying usage charge. Block 1: up to 2.74 kWh per day	No change from the initial proposal.	No change from the draft decision.

Block 2: 2.74 to 16.43 kWh per day Block 3: over 16.43 kWh per day		
We approved Ergon Energy's proposed method for measuring a customer's peak demand as the use recorded in a 30 minute period that falls within its peak charging window during the month. The highest four days are averaged, which moderates the application of the peak charging window. In non-summer months, a minimum of 3 kW demand charge is applied.	No change from the initial proposal.	No change from the draft decision.

Small to medium business customers

We approve Energex's small to medium business proposed demand charge and Ergon Energy's time of use energy and time of use demand charges. We are satisfied that the small to medium business tariffs proposed by Energex and Ergon Energy will contribute to achievement of compliance with the distribution pricing principles.

Energex customers can choose to opt-in to the business time of use or demand tariffs provided they have the appropriate meter. Those customers can also choose to opt-out of these new cost reflective tariffs and revert to their previous flat business tariff.

Ergon Energy's inclining block tariff is the default tariff for existing residential and small-medium business customers. Customers can opt-in to the seasonal time varying and seasonal demand tariffs. They can then opt-out to the default inclining block tariff if they wish. In 2017–18, for a new customer the inclining block tariff is the default tariff. They may opt-in to the time varying and demand tariffs. From 2018–19 new customers will be on the demand tariff by default but can opt-in to the inclining block tariff or the time varying tariff.

The Clean Energy Council stated it broadly supports the approach to network tariff reform proposed by the AER and the distribution businesses in the National Electricity Market (NEM).[2] The Council also noted the importance of customer engagement and consultation continuing, especially to inform the 2020–25 tariff proposals.

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2 Clean Energy Council, *Submission to the AER on SA, ACT, NSW and Queensland Tariff Structure Statements,* 26 October 2016, p. 1.

In contrast, Canegrowers did not think that the Ergon Energy seasonal time of use energy or seasonal time of use demand charge were appropriate for irrigators or cane growers. They consider the peak charging windows were too wide to enable these customers to respond to the tariff and that irrigation customers were not the cause of demand spikes in the Ergon Energy network. They considered that modifications to the time of use energy charge could make it much more beneficial for cane growers and other customers not driving system demand peaks.[3] Nevertheless, Canegrowers is still in favour of cost reflective pricing more generally though.[4]

Table 3: and Table 4: outline our decision for the small to medium business tariffs by distributor.

Table 3: Energex, small to medium business customers

Our draft Decision	Energex revised proposal	Our final decision
We approved Energex's proposed opt-in time of use and demand based tariffs for small to medium business customers (less than 100 MWh/year).	No change from the initial proposal.	No change from the draft decision.
We approved Energex's proposed charging windows for peak, shoulder and off-peak for small to medium business customers on time of use and demand tariffs. Peak: 7am to 9pm weekdays Off-peak: 9pm to 7am weekdays and anytime on weekends	No change from the initial proposal.	No change from the draft decision.
We approved Energex's proposed default tariff being the business flat usage tariff, regardless of meter type, comprising of a fixed charge and a non-varying usage	No change from the initial proposal.	No change from the draft decision.

3 Canegrowers – Sapere – *AER Draft Decision on Ergon Tariff Statement (plus revisions): Review and comments for Canegrowers,* November 2016, p. 4.

4 Canegrowers – Sapere – *Ergon 2015 tariff structure statement: Notes for Canegrowers' meeting with AER*, June 2016 p. 4. Canegrowers – Sapere – *Canegrowers response to AER Issues Paper Tariff Structure Statement Proposals, Queensland electricity distribution network service providers*, 29 April 2016 p. 1. Ergon Energy – Frontier Economics – *Response to Sapere claims on Ergon Energy's Tariff Structure Statement* – December 2016, p.4.

charge.

We approved Energex's proposed method for measuring a customer's peak demand as the highest use recorded in a 30 minute period that falls within its peak charging window during the month. Energex indicated that it would cap the demand charge, at a level to be determined.	Energex has not proposed a cap on the demand charge.	No change from the draft decision.

Table 4: Ergon Energy, small to medium business customers

Our draft Decision	Ergon Energy revised proposal	Our final decision
We approved Ergon Energy's opt-in time of use and demand based tariffs for small to medium business customers.	No change from the initial proposal.	No change from the draft decision.
We approved Ergon Energy's proposed charging windows for peak and off-peak for residential customers. Peak: 10am to 8pm every day (summer time for peak charge) Off-peak: All other times	No change from the initial proposal.	No change from the draft decision.
We approved Ergon Energy's proposed default tariff being the inclining block tariff, regardless of meter type, comprising of a fixed charge and a varying usage charge. Block 1: up to 2.74 kWh per day Block 2: 2.74 to 54.76 kWh per day Block 3: over 54.76 kWh per day	No change from the initial proposal.	No change from the draft decision.
We approved the seasonal	No change from the initial	No change from the draft

time of use energy (STOUE) tariff.	proposal.	decision.
We approved the seasonal time of use demand (STOUD) tariff.	No change from the initial proposal.	No change from the draft decision.
We approved Ergon Energy's proposed method for measuring a customer's peak demand as the use recorded in a 30 minute period that falls within its peak charging window during the month. The highest four days are averaged, which moderates the application of the peak charging window. In non-summer months, a minimum of 3 kW demand charge is applied.	No change from the initial proposal.	No change from the draft decision.

Large business customers

We approve the continuation of Energex and Ergon Energy's large business tariffs—see Table 5: and Table 6:. We are satisfied that they contribute to the achievement of compliance with the distribution pricing principles.

For Energex, no changes were proposed to large customer tariffs from that in the initial tariff structure statement and which we approved in the draft decision.

There was no submission from stakeholders about Energex's large customer tariffs.

There was one confidential submission from some customers who also act as a generation and a source of load on the network on Ergon Energy's large customer tariffs. That submission was in relation to the draft decision for kVAr tariffs.

Regarding those particular tariffs, Ergon Energy made a slight modification to the way the reactive power would be charged for this tariff, following our draft decision on this issue. We have approved the amended method that Ergon Energy has proposed to calculate these tariffs. The result is that affected customers will be less impacted by the kVAr charging than the initial proposal.

Ergon Energy has not made any changes to its large customer tariffs from those that it presently offers, or that it proposed in its initial tariff structure statement.

Table 5: Energex, Large business customers

Our draft decision	Energex revised proposal	Our final decision
We approved Energex's proposed tariffs for large business customers (greater than 100 MWh/year).	Energex proposed an excess demand charge (kVA) for the LV time of use tariff.	No change from the draft decision. Approve existing suite of demand and kVA tariffs.
We approved Energex's proposed charging windows for peak, shoulder and off-peak for small to medium business customers on time of use and demand tariffs. Peak: 7am to 9pm weekdays Off-peak: 9pm to 7am weekdays and anytime on weekends	No change from the initial proposal.	No change from the draft decision.
We approved Energex's proposed default tariff being the business flat usage tariff, regardless of meter type, comprising of a fixed charge and a non-varying usage charge.	No change from the initial proposal.	No change from the draft decision.
We approved Energex's proposed method for measuring a customer's peak demand as the highest use recorded in a 30 minute period that falls within its peak charging window during the month.	No change from the initial proposal.	No change from the draft decision.

Table 6: Ergon Energy, Large business customers

Our draft decision	Ergon Energy revised proposal	Our final decision
We approved Ergon Energy's large customer tariffs. LV large customers (SAC large), large commercial and industrial customers (CAC) and	Minor changes from the initial proposal.	As discussed below.

individually calculated customers (ICC) face mandatory demand tariffs.		
LV large customers (SAC large) face mandatory demand tariffs. The demand tariff incorporates fixed, demand and flat usage charges.	No change from the initial proposal.	No change from the draft decision.
We approved Ergon Energy's proposed charging windows for peak and off-peak for residential customers. Peak: 10am to 8pm every day (summer time for peak charge) Off-peak: All other times	No change from the initial proposal.	No change from the draft decision.
We approved Ergon Energy's proposed default tariff being the inclining block tariff, regardless of meter type, comprising of a fixed charge and a varying usage charge. Block 1: up to 2.74 kWh per day Block 2: 2.74 to 54.76 kWh per day Block 3: over 54.76 kWh per day	No change from the initial proposal.	No change from the draft decision
We approved Ergon Energy's proposed method for measuring a customer's peak demand as the use recorded in a 30 minute period that falls within its peak charging window during the month. The highest four days are averaged, which moderates the application of the peak charging window. In non-summer months, a minimum of 3 kW demand charge is applied.	No change from the initial proposal.	No change from the draft decision.
We did not approve Ergon Energy's excess reactive power charge. The charge has been applied to ICC customers	Ergon Energy submitted that the billing of the excess reactive power charge had been modified such that a	We approve Ergon Energy's excess reactive power charge for its CAC customers, as an incentive

and Ergon Energy proposed to apply it to CAC customers. We received submissions that this charge was not cost reflective in its current form, due to generators placing large loads on the network, often for short periods of time.	generator will not contribute to the load kVAr (kVAr set to zero when generator is in use). Therefore, the excess kVAr charge is to provide sufficient incentive for the customer to correct their power factor. Businesses using up to their authorised demand kVA will not be affected by this charge.	for businesses to correct their power factor.

Calculating forward looking costs

We approve both Queensland distributors proposed methodology for calculating their forward looking long run marginal costs. Noting there are a number of methods that can be used, we are satisfied that the proposed methodology to calculate long run marginal costs contributes to the achievement of compliance with the distribution pricing principles.

Both Energex and Ergon Energy used the average incremental cost approach, which is commonly used by distributors in Australia. We are satisfied that this methodology contributes to achievement of compliance with the distribution pricing principles.

Nevertheless, we still consider it beneficial if replacement capex (repex) is included in the estimates of LRMC. This is because replacement capex is a forward looking cost and is therefore marginal. It is affected by either demand or the value that customers place on existing, or altered network capacity. We expect distribution businesses to consider the way repex should be taken into account in future tariff structure statements.

Further discussion on forward looking costs can be found in Chapter 7.

Stakeholder engagement

We consider that Energex and Ergon Energy have made efforts to effectively engage with customers, retailers and customer representatives where possible. This helped formulate the design of their cost reflective tariffs.

Feedback to us about the distributors' stakeholder consultation has been generally positive. Stakeholders submitted they have been given the opportunity to comment on distributors' proposals for cost reflective tariffs and to influence the tariff structure statements content. Nevertheless, this has not resulted in consensus among stakeholders and the distributors about the type and nature of tariffs to be introduced.

Energex noted that not all residential customers were convinced that demand tariffs were the best means of cost reflective tariffs. Time of use tariffs (presumably energy only charging in kWh) were preferred by some stakeholders.[5] Energex observed that demand tariffs have been well supported across industry. Its own rewards based tariff trial from 2011–13 was also influential in showing that residential customers could understand demand tariffs, and respond to them.[6] Ergon Energy also undertook considerable consultation to develop its tariff structures and considered that a combination of time of use and demand tariffs were an appropriate response to the new Rules requirements for cost reflective pricing.

See Appendix A for more detail on stakeholder engagement.

Our process

Table 7 sets out how this tariff statement final decision follows on from the Power of Choice reform program and into the first annual pricing approval process.

As outlined below, the Energex and Ergon Energy submitted their initial tariff structure statement proposals in November 2015 as required by the Rules.

We made a draft decision in August 2016 that approved the initial tariff structure statements but made some recommendations for additional information the distributors should provide in their revised proposals. Revised proposal were submitted October 2016.

We also took into account stakeholder submissions received on the initial proposals, comments received at our April 2016 public forum, our discussions with stakeholders which were conducted either individually or in a group, and submissions made on the revised tariff structure statements. We held an addition meeting with Canegrowers and Ergon Energy after the revised tariff structure statement was submitted. The meeting and subsequent exchanges resulted in further public submissions after the submission deadline from Canegrowers and Ergon Energy. Those submissions are available on our website and are considered in our final decision.

Table 7: Tariff structure statement and annual pricing process timeframes

Reform milestones	Date
Tariff structure statement process	
Ergon Energy and Energex submits tariff structure proposal to AER	27 November 2015
AER publishes issues paper	11 March 2016

[5] Energex, *Tariff Structure Statement – Explanatory notes, 1 July 2017 to 30 June 2020*, 4 October 2016, p.p. A.3-4.

[6] Energex, *Tariff Structure Statement – Explanatory notes, 1 July 2017 to 30 June 2020*, 4 October 2016, p. 29.

AER hosts public forum on Ergon Energy and Energex's proposals	13 April 2016
Stakeholders' submissions on Ergon Energy and Energex's proposal and AER's issues paper closed	28 April 2016
AER publishes draft decision	2 August 2016
Ergon Energy and Energex's revised proposal and stakeholders' submissions on AER's draft decision due	4 October 2016
Stakeholders' submissions on Ergon Energy and Energex's revised proposal and other stakeholders' submissions due	25 October 2016
Stakeholder meeting with Canegrowers and Sapere	29 September 2016
Stakeholder meeting with Ergon Energy, Energeia, Frontier Economics, Canegrowers, Sapere, Qld Dept of Energy and Water Supply	2 November 2016
AER publishes final decision	28 February 2017
First annual pricing proposal process to apply tariff structure statement	
Ergon Energy and Energex submits annual pricing proposal	31 March 2017
AER publishes decision	17 May 2017
New tariffs take effect	1 July 2017

Future direction

This is the first tariff structure statement submitted by Energex and Ergon Energy. The move to full cost reflective pricing will take time to implement. The distribution pricing principles require movement towards more cost reflective tariffs with every tariff statement proposal over upcoming regulatory control periods.

There are some elements of Energex and Ergon Energy's proposal which, while seen as a reasonable first step in meeting the distribution pricing principles, would, in our view, benefit from further consideration in developing future tariff structure statements. We identify these matters to provide guidance to Energex and Ergon Energy, and the industry more generally, on our views on the direction the industry should be heading in in order to maintain compliance with the distribution pricing principles in the future. Accordingly, we expect distributors to propose additional reforms in each round of tariff structure statements in order to keep progressing towards full cost reflective pricing.

We encourage Energex and Ergon Energy to make further improvements in the following areas in the next round of tariff structure statements:

- Greater integration between Energex and Ergon Energy network pricing, network planning and demand management strategies (see discussion in chapter 1)
- Assignment policies and speed of transition to cost reflective tariffs (see discussion in chapters 4, 5 and 6)
- Method for estimating long run marginal cost (see discussion in chapter 7)
- Inclusion of replacement capital within Energex and Ergon Energy's long run marginal cost estimates (see discussion in chapter 7)
- Reconsideration of the use of a 30 minute window to measure demand (see discussion in chapter 5 and 8)
- Refinements to charging windows and the methods used to develop charging windows (see discussion in chapter 8)

We briefly discuss the topic of tariff assignment polices and the pace of reform below, with more detail on this topic found in chapters 4, 5 and 6. The other topics listed above are discussed in the sections referenced at the end of each dot point.

Assignment policies and pace of reform

Currently, a key barrier to the assignment of residential and small business customers to cost reflective network tariffs is the metering technology. Outside Victoria, most residential and small business customers currently have an accumulation meter which measures the total amount of consumption, but not when this consumption occurs. It is therefore not possible to implement cost reflective network tariffs for customers with accumulation meters.

Changes to the metering rules mean that, from 1 December 2017, all new and replacement meters must be a smart meter.[7] Smart meters make the implementation of cost reflective network tariffs possible because they measure both total consumption and when this consumption occurs.

As this metering barrier to tariff reform gradually disappears, a key determining factor of the pace of network tariff reform will be whether customers are assigned to cost reflective network tariffs on a "mandatory", "opt-out" or "opt-in" basis. While opt-in approaches have been a feature of this first phase of tariff reform in some jurisdictions, they are likely to lead to slower movement towards more cost-reflective tariffs than mandatory or opt-out approaches. This is because continued opt-in arrangements are not likely to encourage sufficient uptake to enable successful tariff reform. Experience of opt-in arrangements demonstrates relying on such arrangements may delay tariff reform implementation. Whereas opt-out arrangements, where trialled, have been more successful. ActewAGL's experience presents a useful case study of the results from these differing approaches. ActewAGL stated:

[7] AEMC, Rule determination—National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, November 2014.

> Our experience in implementing tariff reform over the last decade demonstrates that opt-in tariffs are relatively ineffective in migrating consumers to more cost reflective tariffs. Between 2007 and 2010 [ActewAGL] rolled out interval meters, together with opt-in time-of-use tariffs. The consumer response was minimal with only 30 customers opting in to the residential time-of-use tariff. However, when the tariff assignment policy changed to time-of-use tariffs being the default tariffs for new connections, (but with the choice to opt-out), the incidence of opting out has been negligible.[8]

The Network Pricing Objective states that the tariffs a distributor charges should reflect the distributor's efficient costs of providing its direct control services to the retail customer.[9] These charges are paid by the customer's retailer. Our view is the price signals faced by the retailer should be cost reflective in order to meet this objective. The retailer will then be in the position to decide whether it passes those costs through to end customers and in what form. In other words, the main objective of network tariff reform is that retailers are exposed to the costs of network congestion or the costs of using the network when it is under the greatest demand pressure. Being exposed to these costs will mean that retailers will have an incentive to manage this exposure and take actions that reduce network congestion, such as setting prices higher in such periods to reduce demand (or the use of non-price measures such as demand management). In the long run, we consider this should be facilitated by assigning all customers to cost reflective network tariffs. We consider the best method to transition to this objective is through an opt-out approach in the next round of tariff structure statements, for customers with appropriate metering technology, and also based on other appropriate tariff assignment criteria which we discuss in this decision.

There are mixed views from stakeholders on whether mandatory or opt-out approaches should be the norm in these initial stages of tariff reform, or whether most reliance should be on placed on opt-in approaches. We consider stakeholders would benefit from further information regarding the differing functions of retailers and consumers in relation to network tariff assignments as the pace of reform increases in the lead up to the next tariff statement periods.

Typically end customers are not directly involved in the process of selecting which network tariff they are assigned to. It is the retailer who submits the application to a distributor which determines what type of network tariff an end customer is assigned (where the distributor provides a choice over this assignment). End customers are involved in selecting the type of retail tariff that best meets their requirements.

Network tariff structures are not required by the Rules to be reflected in retail tariff structures, so we do not yet know how retailers will respond to the new cost reflective network tariffs. We consider that even under mandatory or opt-out network tariff assignment policies it is likely end customers, especially residential and small business

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[8] ActewAGL, Re: Issues paper—Tariff structure statement proposal, ActewAGL, Submission to AER, 28 April 2016, p.5.

[9] NER, cl. 6.18.5(a).

customers, would continue to have a choice from retailers over their retail tariff structure. Rather, cost reflective network tariffs place an incentive on retailers to respond to these peak price signals, as they are the ones who must pay the network tariffs.

Retailers will choose how they respond to these new price signals. In supplying electricity to customers, retailers manage a number of different input costs, including:

- transmission and distribution network charges
- generation (energy) charges
- other costs of providing the service to customers, such as the cost of complying with government environmental policies, marketing and retail billing costs.

Residential and small business customers do not pay these input costs directly. Nor is the structure of these cost inputs necessarily reflected in retail tariff structures. For example, retailers face generation changes which change every five minutes and are averaged over every 30 minutes (spot prices). However, retail tariff structures do not change every 30 minutes. Rather, end customers typically face flat rate retail tariffs. This is because, in developing pricing offers for customers, retailers package all of these input costs and manage the risk of differences between spot prices and the prices paid by customers. Customers then select from a range of different offers from different retailers that best meet their preferences. As the AEMC stated:

> The role of the networks is to provide cost-reflective [network] pricing. The retailers' role is to take wholesale costs, network charges and other potential energy services such as distributed generation or energy management systems, and package these up for consumers. In many ways, their job is to be the consumers' agent for dealing with the rest of the system. Successful retailers are those that offer the most attractive packages to consumers. And remember in this new energy environment, the term retailer means any business that comes to market offering energy services. Because consumers are so different, we should expect there to be great diversity in the products, services and tariffs offered and taken up. Consumers choose between fixed and variable mortgages with different terms in the financial sector; and they choose from a range of mobile phone packages in the telecommunications sector.
>
> Network pricing reform in the energy sector is about sending price signals to consumers – and more precisely to competing retailers – about the cost of using the network in different ways and at different times. This means consumers can make the consumption choices they want to, while allowing co-ordination of the various elements of the energy supply chain.[10]

[10] AEMC, *Ensuring the regulatory framework facilitates competitive and efficient energy markets in a time of technological change: Address at Australian Energy Week 2016*, 21 June 2016, p. 4.

Similarly, we anticipate that even if all end customers were assigned to a cost reflective network tariff structure, this does not mean they will be necessarily required to face a retail tariff that exactly matches the network tariff structure. Retailers may respond to the new network tariffs in different ways: some retailers may fully reflect the new network tariff structures in their own retail tariffs, while others do not. Some retailers may give customers the choice as to whether they want to face a retail tariff that reflects the network tariff structure.

Retailers have a number of tools to help them manage the risk of differences in network and retail price structures and price that risk efficiently. Retailers are in the best position to manage the risks of any mismatch between their offers to customers and the cost structures the retailer faces in terms of network and wholesale electricity costs. It is unlikely retailers will all respond in exactly the same way in addressing these risks, either in terms of structure or timing. We would also expect further innovation from retailers as network tariff reforms mature and are progressively rolled out. One option retailers have to manage these risks will be to develop retail tariff structures that reflect the network tariff structure—either in full or in a simplified form. Retailers may develop such retail offerings and customers would have a choice as to whether they want to sign up to these offers. However, this is not the only option retailers have to manage this risk. Other options for retailers might include retail offerings which are:

- based on flat rate retail tariffs, but allow the retailer to manage the load of the end customer during times of peak network congestion (and therefore times when the retailer is paying the peak network charges), if the end customer agrees to allow the retailer to manage its consumption in this way (this is a form of non-price or demand management solution)
- based on flat rate retail tariffs, but include a risk premium to compensate the retailer for the risk it faces in the mismatch between the cost reflective network tariffs it pays, and the flat retail tariffs it receives.

These are just some of the possible options open to retailers. When retailers face the costs of network congestion in network tariffs, we expect this will spur retailers and other third parties to develop innovative solutions to manage this cost. While this reform refers to the restructuring of network tariffs, it is equally important for retailers to engage with the tariff reform process and consider what reforms to retail tariffs will be necessary to provide customers with the ability to understand the implications of the changes to network tariffs to make better decisions about their energy choices.

Without cost reflective network pricing, the main option for distributors to manage the risk of congestion on their networks is to “build out” the congestion through investments in network augmentation (or adopt non-price demand management solutions). However, in the absence of cost reflective network tariffs (or other measures to manage demand) this network investment will occur even when it is inefficient. In other words, without cost reflective network tariffs, network investment will occur even when consumers value the added reliability from the investment less than the cost of the investment. The effect of a continued reliance on opt-in arrangements may be that the cost of managing those risks of network congestion is borne by all customers instead of the particular customers whose decisions cause that congestion. This can lead to higher prices for all customers and reduced incentives on retailers to provide innovative tariffs and reduced incentives on retailers and third party providers to provide demand management services.

The Energy Networks Association has estimated that cost reflective tariffs can lead to savings of $17.7 billion in present value terms over a 20 year period.[11] Former AGL chief economist Paul Simhauser estimated that hardship customers are among the biggest beneficiaries of cost reflective network tariff reform, with working couples and concession customers (e.g. pensioners) also better off. The study showed that, under current pricing structures, an average customer in a hardship program was most likely to be paying more than the costs they impose on the network for providing them with network services. This is because, on average, customers in a hardship program use a greater proportion of their energy at off-peak times compared with other customer types.[12] Therefore, moving away from network pricing based on the customer's total consumption and towards pricing based on consumption during peak times will benefit these types of customers, even if they make no changes to the total amount of electricity they consume or when they use electricity.

Network tariff reform may also increase the reliability of the grid, by reducing the pressure on the grid during peak times.

For all of these reasons it is vital that we see a substantial effort to accelerate the pace of network tariff reform in the next tariff structure statement period for all distributors—these coincide with their next regulatory control periods. This requires network tariffs to become more cost reflective so that retailers face the costs of network congestion and they are encouraged to develop innovative retail solutions to manage this cost. This will provide customers with the ability to understand the implications of the changes to network tariffs to make better decisions about their energy choices.

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11 Energy Networks Association, *Network pricing and enabling metering analysis*, Prepared by ENERGEIA for the Energy Networks Association, November 2014, p.5.

12 Paul Simshauser and David Downer, *On the inequity of flat-rate electricity tariffs*, AGL Applied Economic and Policy Research, Working Paper No. 41 – Inequity of Tariffs, 2014, pp.10-13; pp.18-19.

1 Background

The requirement on distributors to prepare a tariff structure statement arises from a significant process of reform to the National Electricity Rules (the Rules) governing distribution network pricing. The purpose of the reforms is to empower customers to make informed choices by:

- Providing better price signals—tariffs that reflect what it costs to use electricity at different times so that customers can make informed decisions to better manage their bills.
- Transitioning to greater cost reflectivity—requiring distributors to explicitly consider the impacts of tariff changes on customers, and engaging with customers, customer representatives and retailers in developing network tariff proposals over time.
- 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.

Why is network tariff reform important?

Distribution tariffs historically have not varied according to the time when electricity is used. But distribution costs are significantly driven by the peak demand the network must cater for at times of congestion on the network. This means the structure of existing network tariffs don't reflect network costs. Most existing retail tariffs send price signals that don't inform customers about the costs imposed on distribution networks in peak demand periods.

Lifestyle changes, including the use of air conditioners during hot summer periods, means customers now use relatively more of their electricity at peak times, even if overall energy consumption has declined. Network costs have increased over the last decade as distributors invest in additional infrastructure upgrades to meet the higher peak demand. This increased investment has been a factor driving electricity price rises in the last decade.[13]

Given that there is far greater diversity today in how customers use electricity, it is important for customers to understand the value of their choices. Moving to network tariffs that reflect electricity use during peak demand periods will make electricity pricing more transparent.

As such, cost reflective pricing means the network tariffs retailers pay more accurately reflect the way electricity is used by customers. Retailers whose customers use electricity at peak times should pay rates better reflecting the costs created by their

[13] Over the last couple of years, network costs and prices have started to flattened out or even decrease in some areas. This has been due, in part, to lower financing costs associated with these network investments.

use. Customers who use less electricity in peak demand periods and more at other times should benefit from lower network prices during non–peak times by their retailer offering them lower retail prices during these times. And if customers are given the opportunity to respond to these price signals by their retailer, network investment requirements will be lower than they otherwise would be. This reduces upwards pressure on electricity prices for everyone.

What are the key concepts to understand?

This final decision incorporates concepts which may be unfamiliar to some readers. In this section we provide descriptions of the more commonly used concepts. Readers familiar with electricity network regulation and terminology may choose to skip to the next section.

Difference between demand and consumption

Electricity consumption is the total amount of electricity consumed (used) over a period of time. For example, a typical Australian household might use between 5,000kWh to 6,000 kWh of electricity over 12 months.[14] Demand means the amount of electricity used at a single point in time. Peak demand is the maximum amount of electricity used at a single point in time over a defined time period, often a day or a year. A typical Australian household might have its yearly peak demand of around 5kW, either on a hot summer afternoon when air conditioning is used, or on a winter evening when electric heating is used.[15] That is, the household's annual peak demand is 5kW.

A good analogy for electricity consumption compared to electricity demand is a river flowing under a bridge. Annual electricity consumption is equivalent to the total water volume flowing under the bridge during a year. Electricity demand is equivalent to the volume of water under the bridge at a single point in time. Peak electricity demand is equivalent to the time when the largest volume of water is flowing under the bridge.

Long run marginal cost and residual costs

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. Long run marginal cost could also be described as a distributor's forward looking costs that are responsive to changes in electricity demand. This could include replacement of fixed assets at the end of their economic life.

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14 Total consumption for a 'representative' residential household is estimated to fall between 5,000 kWh and 6,000 kWh in Queensland, NSW and South Australia. Total consumption for a representative residential household is lowest in Victoria (at around 4,000 kWh) and highest in the ACT (at around 7,000 kWh). AEMC, *2016 Residential electricity price trends—Final report*, December 2016, p.xii.

15 EMET Consultants Pty Ltd as referenced by solarchoice.net.au.

The Rules require network tariffs to be based on long run marginal cost.[16] However, not all of a distributor's costs are forward looking and responsive to changes in electricity demand. Hence, if network tariffs only reflected long run marginal cost, distributors would not recover all their costs. Costs not covered by a distributor's long run marginal cost are called 'residual costs'. The Rules 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 costs.[17]

Types of network tariffs

A network ’tariff’ is the combination of charges that are billed to a customer’s retailer in return for the distributor providing network services to that customer. Historically, most residential and small business customers in Australia have been on either a flat tariff or a block tariff (tiered pricing):

- **Flat tariff**—usually consists of a fixed charge and flat usage charge. That is, usage is charged the same price per unit of electricity consumed no matter how much electricity the customer uses.
- **Inclining block tariff**—usually consists of a fixed charge and a series of block charges where the price per unit of electricity consumed changes depending on the size of the customer's total consumption. The first consumption block is charged the lowest price, and each successive block of consumption is charged at higher rates.
- **Declining block tariff**—usually consists of a fixed charge and a series of block charges where the price per unit of electricity consumed changes depending on the size of the customer's total consumption. The first consumption block is charged the highest price, and each successive block of consumption is charged at lower rates. A declining block tariff is the reverse of an inclining block tariff.

Flat tariffs or inclining block tariffs are relatively common. Declining block tariffs are now relatively uncommon in most jurisdictions. Neither flat tariffs nor block tariffs are cost reflective. As explained above, network costs are largely driven by consumption during peak demand periods, with electricity consumption during off-peak periods relatively inexpensive to provide. However, the tariff structures of flat and block tariffs are unrelated to whether the customer is consuming electricity during peak or off-peak periods.

In contrast, time-of-use tariffs, demand tariffs and critical peak pricing are all more cost reflective forms of network tariffs. This is because the tariff structures under each of these tariffs is related to whether the customer is consuming electricity during peak or off-peak periods. Each of these tariffs is explained further below.

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16 NER, cl. 6.18.5(f).

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

A **time-of-use (TOU) tariff** usually also has a combination of fixed and usage charges (similar to flat and block tariffs). The difference is that time-of-use tariffs apply a different usage charge depending on when the customer consumes electricity. A time-of-use tariff will have defined charging windows when different rates apply. These charging windows might be labelled the 'peak' window, 'shoulder' window, and 'off-peak' window. The highest usage rate applies to consumption during the peak window, and the lowest usage rate applies to consumption during the off-peak window.

A **demand tariff** includes a charge based on the customer's highest measured demand during a specified period of time (e.g. over the billing period). Often, demand charges will be limited to the highest demand measured during peak charging windows. Typically, charging windows will coincide with the peak demand times for the whole network or for specific customer types (e.g. residential or small business customers). Demand tariffs may also include fixed charges and usage charges.

Critical peak pricing is another tariff variant and an example of more dynamic tariffs. Under this approach a distributor can specify periods of critical network peak demand, and will set prices particularly high for any demand or consumption that occurs during the specified critical peak event. This approach is generally in use currently only for certain larger business customers who can moderate consumption (e.g. by shutting down part of a production line) or use their own generation assets as a substitute for network electricity.

Distributors sometimes offer combinations of a primary tariff, such as those listed above, with secondary tariffs, such as controlled load tariffs. These controlled load tariffs typically apply a lower rate to electricity used for certain appliances in return for only being able to use those appliances during off peak times. For example, off peak hot water. In other cases, a lower rate may apply to customers who allow a distributor to remotely cycle appliances on and off during peak demand periods. For example, CitiPower and Powercor have tested technology to cycle customers' air conditioning. They are now considering how to trial this technology with customers.[18] Distributors will often limit access to secondary tariffs to customers on specified primary tariffs such as flat tariffs or block tariffs.

In addition to tariffs, distributors sometimes seek to influence demand by offering rebates (partial refunds) to customers in return for demand reductions made by the customer during specific time periods. Rebates may be linked to critical peak demand times or to specific geographic areas or both.

Metering and tariffs

Flat tariffs or block tariffs can be applied to customers with basic accumulation meters (type 6 meters). This is because to calculate the tariff, it is only necessary to know the customer's total consumption, not when that consumption has occurred.

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[18] CitiPower and Powercor, Email to AER staff, *Remote air-conditioning cycling through meters or other means in Victoria*, 12 August 2016.

In Victoria, all customers with annual consumption of less than 160MWh have advanced metering infrastructure (AMI)—commonly referred to as **smart meters**—since 2009. The installation of these meters was undertaken by the five electricity distributors as part of a State Government mandated rollout. Smart meters can facilitate time-of-use or demand tariffs or more dynamic tariffs. This is because they measure both when, where and how much electricity a customer has consumed, which is necessary to calculate a time-of-use tariff or demand tariff. These meters are read remotely through communications functionality that is included in this metering infrastructure.

Outside Victoria, smart meters will become the standard for residential and small business customers for all new connections and existing premises where the meter must be replaced, from 1 December 2017. This means that in those states and territories outside Victoria that smart meters will gradually become increasingly common over time.

Degree of choice in network tariff assignment

A constituent element of a tariff structure statement are the policies and procedures a distributor will apply for assigning customers to network tariffs or reassigning customers from one network tariff to another.[19] These policies and procedures should include certainty around whether a tariff is a 'mandatory' tariff, 'opt-out' tariff or 'opt-in' tariff for particular customer types. Among other possibilities, customer types might be based on the connection characteristics and metering arrangements of the customer, as well as whether the customer is a new or existing customer. The differences between these three options are:

- **A mandatory tariff**—means this is the only network tariff available for customers of a particular type. For example, industrial customers connected to the high voltage network and whose annual consumption falls within a particular range may be required to be assigned to a particular demand tariff, and there may be no other tariff options available to their retailer for them to choose from.
- **An opt-out tariff**—means the customer is assigned to this network tariff by default, but the customer (through their retailer) can choose to be re-assigned to a different tariff. For example, a residential customer may by default be assigned to a block tariff, but could (through their retailer) choose to switch to a time-of-use tariff.
- **An opt-in tariff**—means the customer (through their retailer) can choose to be re-assigned to this tariff, but the customer is by default assigned to some other network tariff. This is the opposite of an opt-out tariff. In the previous example, the time-of-use tariff would be described as an opt-in tariff.

It is important that distributors are clear in their tariff structure statements which of their proposed tariffs are mandatory, opt-out and opt-in, and for which customer types.

[19] NER, cl.6.18.1A(a)(2).

Typically end customers are not directly involved in the process of selecting which *network tariff* they are assigned to. It is the retailer who submits the application to a distributor which determines what type of network tariff an end customer is assigned (where the distributor provides a choice over this assignment). End customers are involved in selecting the type of *retail tariff* that best meets their requirements.

Network tariff structures are not required by the Rules to be reflected in retail tariff structures, so we do not yet know how retailers will respond to the new cost reflective network tariffs. We consider that even under mandatory or opt-out network tariff assignment policies it is likely end customers, especially residential and small business customers, would continue to have a choice from retailers over their retail tariff structure. Rather, cost reflective network tariffs place an incentive on *retailers* to respond to these peak price signals, as they are the ones who must pay the network tariffs.

To assign customers to one of the various tariffs offered by a distributor requires also that the distributor group customers into types, or classes. Customer classes might be based on a customer's connection type or metering arrangements, their annual usage, or whether the customer is a new or existing customer.

Elements of a tariff structure

A tariff structure incorporates the charges that make up a tariff. For example, a demand tariff typically comprises a fixed charge, a usage charge and a demand charge. How those charges are applied to a customer reflect the tariff's charging parameters. The design of a charging parameter might include:

- how frequently a charge is applied to a customer
- the times during which usage or demand is measured to calculate a charge
- variations in charges and how those variations are triggered.

Charging parameters may be varied to match the purpose of the distributor when designing the tariff. For example, the demand charge within a demand tariff may target the time of a distributor's broad network peak, a local regional peak, or a customer class peak (e.g. residential customers).

A group of customers with similar connection and usage characteristics will be grouped into the same tariff class. There can be multiple tariffs within a tariff class to which a customer could be assigned.

How does the tariff structure statement fit into the regulatory process?

Tariff structure statements are a new element of the Rules. Generally, tariff structure statements will be submitted to us by distributors with their regulatory proposals for us to assess and determine how much revenue they are allowed to earn over the next regulatory control period (which is typically a five year period). Within this usual distribution determination process we will publish, assess and invite feedback on a tariff structure statement along with a distributor's regulatory proposal. An approved tariff structure statement will then apply to the distributors' tariffs for the coming five year regulatory control period.

In this case, for the first round of tariff structure statements for each distributor, the Rules require tariff structure statements be submitted outside the distribution determination process for all distributors, other than TasNetworks . This is because the timing of the introduction of tariff structure statements is occurring midway through the regulatory control period for all distributors other than TasNetworks.

The timing of TasNetworks' distribution determination enabled the Australian Energy Market Commission to specify in the Rules that TasNetworks' tariff structure statement be submitted with its distribution determination. The upcoming distribution regulatory period for TasNetworks is to be only two years long. Hence, TasNetworks' initial tariff structure statement will apply for only two years.

For other distributors the next distribution determination processes are too far into the future for the usual process to be followed. Delaying submission of the initial tariff structure statement for those distributors would unduly delay the tariff reform process. For distributors in South Australia, Victoria, New South Wales, the Australian Capital Territory and Queensland, the Rules required that tariff structure statements be submitted in advance of the next distribution determination. The initial tariff structure statements for these distributors will also apply for abbreviated periods, reflecting the time remaining until their next distribution determination. For ACT and NSW distributors, this is two years, covering the period 1 July 2017 to 30 June 2019. For Queensland and South Australian distributors, this is three years, covering the period from 1 July 2017 to 30 June 2020. For Victorian distributors, this is four years, covering the period from 1 January 2017 to 31 December 2020. For all distributors, their first tariff structure statement comes into effect in 2017.

Once approved, a tariff structure statement will guide a distributor in shaping its annual pricing proposals, submitted to us prior to each regulatory year. The annual pricing proposal is where a distributor translates the total allowed revenue from its distribution determination, and the allowed tariff structures from its tariff structure statement, into prices for individual tariffs.

We check that total expected revenue to be earned in the coming regulatory year is consistent with the annual revenue we determined may be earned in that year. We will now also check that an annual pricing proposal is consistent with a distributor's approved tariff structure statement. For example, a distributor may not propose a tariff which was not included in its approved tariff structure statement.[20] Nor may a distributor vary the parameters of a tariff from that described in its tariff structure statement. This provides retailers, customers and other stakeholders with certainty about the structure of tariffs to be charged in each year of the regulatory control period.

[20] The exemption to this is trial tariffs. Distributors may trial new tariffs that were not approved through the tariff structure statement is the tariff meets the requirements in cl. 6.18.1C of the Rules.

Tariff structure statements, in principle, address tariffs for both standard control services and alternative control services. However, in practice the tariffs for alternative control services are almost entirely dealt with by our distribution determinations and the annual pricing approval process. There is relatively little regulatory role left for tariff structure statements in the context of alternative control services. For this reason distributors deal with alternative control services in their tariff structure statements relatively briefly. For the same reason our tariff structure statement decisions will focus on standard control services and make relatively little comment on a distributor's alternative control services.

How does network pricing reform interact with other reforms?

Network tariff reform is commencing at the same time as reforms to the provision of metering services and access to customer information. These related reforms have implications for network tariffs, including the pace at which tariffs can evolve to become more cost reflective.

For metering, changes to the Rules will establish new minimum specifications similar to smart meters currently in use. Smart metering is already in use across Victoria as a result of the mandated smart meter rollout. This has resulted in better meter functionality and data flows and facilitates broader use of more cost reflective pricing over time.

Not all consumers might want to use their own detailed consumption data and instead engage an energy services provider or retailer to use this information to recommend bundled energy plans. In recognition of the changing nature of how customer energy usage information might become available and used, reforms were also recently introduced to make it easier to obtain access to this information.[21] Customers will now be able to access their data from their distributor or retailer, and grant access to other parties to do so on their behalf. These reforms will not only help customers but also energy service providers in developing and offering more tailored and innovative energy products and services over time.

How does network pricing interact with network planning and demand management?

Demand pressures can be addressed by sending price signals to encourage customers (and retailers) to reduce demand, consistent with the aims of tariff reform. Alternatively, demand pressures can be addressed by network expenditure, as has been the case in the recent past. Another option, which distributors are required by the Rules to consider, is the use of demand management initiatives. These can include rebates for customers who reduce their consumption. Or distributors can install or utilise generation assets in areas where the associated cost is less than the cost of

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[21] Australian Energy Markets Commission, National Electricity Amendment (Customer access to information about their energy consumption) Rule 2014, Final Determination, 6 November 2014.

network investment to meet local area demand. Distributors can adopt some demand management solutions directly themselves, whereas other demand management solutions must be procured through an affiliated entity or other third party in accordance with the requirements of our ring fencing guideline.

We consider it useful for tariff structure statements to describe the distributor's approach to integrating tariff reform, network investment and demand management. Such discussion will position tariff structure statements within the broader context of how distributors intend to respond to demand and service challenges. Also, while the Rules require distributors to consider the time and location varying nature of network cost drivers, difficulties with locational pricing suggest a larger role for demand management initiatives to address local network demand pressures.

An example of this is United Energy’s use of rebates for customers in selected locations within its network, to encourage demand reductions that will limit peak demand.[22] This will alleviate, or postpone, the need for more costly network upgrades to those areas where network constraints may be likely in the near term, and still ensure continuing electricity supply and reliability. CitiPower and Powercor also flagged an intention to trial critical peak rebates and tariffs for similar reasons to United Energy.

As new technologies emerge in energy markets, it is anticipated that distributors will also focus on demand management and other non-network solutions to complement pricing as a means to reduce peak demand (where the cost of meeting that peak demand is higher than the value customers place on electricity use during those times) and delivering electricity efficiently.

22 United Energy, *Revised Tariff Structure Statement 2017–20*, 29 April 2016, p. 34-35.

2 Rule Requirements

The amendments to the pricing provisions of the Rules have three aims, namely to provide:

- better signals of the cost drivers of distribution networks
- explicit consideration of tariff change impacts
- transparency and greater certainty on tariff strategies for a regulatory period.

A new network pricing objective is to be the focus for distributors when developing their network prices. This objective is that:[23]

> …the tariffs that a distributor charges for provision of direct control services to a retail customer should reflect the distributors' efficient costs of providing those services to the retail customer

Publication of a tariff structure statement is part of the new tariff arrangements. It should show how a distributor applied the distribution pricing principles to develop its price structures and indicative price levels for the coming five year regulatory period.[24] A distributor must submit its proposed tariff structure statement to us for assessment.

Generally, a distributor will be required to submit its proposed tariff structure statement when submitting its regulatory proposal.[25] The Rules permitted submission of a tariff structure statement outside the regulatory proposal process this time because of the timing of the rule changes.[26]

Tariff structure statement requirements

There are two distinct sets of requirements for tariff structure statements. First, the Rules set out the elements that an approved tariff structure statement must contain.[27] Second, a tariff structure statement must also comply with the distribution pricing principles.[28]

What must a tariff structure statement contain?

The Rules require a tariff structure statement to include:[29]

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23 NER, cl. 6.18.5(a).

24 This is a reference to the Rules' *pricing principles for direct control services*, alternatively described in this decision as the "distribution pricing principles"; NER, cl. 6.18.5(e)–(j).

25 NER, cl. 6.8.2(a).

26 NER, cl. 11.76.2(a).

27 NER, cl 6.18.1A(a) and (e)

28 NER, cl 6.18.1A(b). The distribution pricing principles are prescribed in cl 6.18.5.

29 NER, cl. 6.18.1A(a).

- the tariff classes into which retail customers for direct control services will be divided
- 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 tariff structure statement must be accompanied by an indicative pricing schedule.[30]

What must a tariff structure statement comply with?

A tariff structure statement must comply with the distribution pricing principles, which 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[31]
- 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 and customer location[32]
- 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[33]
- distributors must consider the impact on customers of tariff changes and may vary from efficient tariffs, having regard to:[34]
    - 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 decisions
- tariff structures must be understandable to customers[35]
- tariffs must otherwise comply with the Rules and any other applicable regulatory requirements.[36]

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30 NER, cl. 6.8.2(d1).
31 NER, cl. 6.18.5(e).
32 NER, cl. 6.18.5(f).
33 NER, cl. 6.18.5(g).
34 NER, cl.6.18.5(h).
35 NER, cl. 6.18.5(i).

For the purpose of achieving compliance with the last three principles, the tariff structure statement may depart from comprehensive compliance with the first three principles. Where the distributor does make such a departure, it must explain its reasons for doing so.[37]

Tariff structure statement process

Our role in approving a distributor's tariff structure statement

We must approve a distributor's tariff structure statement unless we are reasonably satisfied that the proposed tariff structure statement does not comply with the distribution pricing principles or other applicable requirements of the Rules.[38] We make one holistic determination to approve or refuse to approve the distributor's tariff structure statement. Our analysis on each element of the distributor's tariff structure statement contributes to our overall assessment.

What happens when a distributor submits a proposed tariff structure statement?

The Rules require us to publish the distributor’s proposed tariff structure statement and invite submissions.[39] We then assess a proposed tariff structure statement for its compliance with the distribution pricing principles and other applicable requirements of the Rules. Taking into account submissions and any supporting information submitted by the distributor, we will publish a draft decision on the proposed tariff structure statement.[40] This will set out our reasons for making the decision.[41]

Our role is largely one of assessing compliance. We must approve a proposed tariff structure statement unless we are reasonably satisfied that it does not comply with the distribution pricing principles or other applicable requirements of the Rules.[42]

What happens if a proposed tariff structure statement is not approved?

A distributor may submit a revised tariff structure statement no later than 45 business days after we publish our draft decision.[43] Under the Rules, a distributor may only make revisions to its tariff structure statement to address matters raised by our draft decision.[44] We will publish the distributor’s revised tariff structure statement and again call for submissions before making a final decision.[45]

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

37 NER, cl 6.8.2(7) and 6.18.5(c).

38 NER, cl 6.12.3(k).

39 NER, cl. 6.9.3(a).

40 NER, cl. 6.10.2; cl. 11.76.2(a).

41 NER, cl. 6.10.2(a)(3); cl. 11.76.2.

42 NER, cl. 6.12.3(k).

43 NER, cl. 6.10.3(a).

44 NER, cl. 6.10.3(b).

45 NER, cl. 6.10.3(d)(e).

What happens after a tariff structure statement is approved?

Once approved, a tariff structure statement will remain in effect for the relevant regulatory control period.[46] The distributor must comply with the approved tariff structure statement when setting prices annually for direct control services.[47]

We will separately assess the distributor's annual pricing proposals for the coming 12 months. Our assessment of annual pricing proposals will also be to ensure consistency with the requirements of the approved tariff structure statement.

An approved tariff structure statement may only be amended within a regulatory control period with our approval.[48] 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 so that the amended tariff structure statement materially better complies with the distribution pricing principles.[49]

[46] Tariff Structure Statements may only be amended during a regulatory period, with our approval, if an event occurs that is beyond the distributors' reasonable control and could not reasonably have been foreseeable requires a change.

[47] NER, cl. 6.18.1A(c).

[48] NER, cl. 6.18.1B.

[49] NER, cl. 6.18.1B(d).

3 Tariff Classes

In our draft decision we accepted the tariff classes proposed by Energex and Ergon Energy.

The Queensland's distributors' tariff classes group similar customers together taking into account their connection to and use of the network. Therefore, we are satisfied that Energex and Ergon Energy's proposed tariff classes are compliant with the rule requirements on the assignment and re-assignment of customers to tariff classes.

Table 3-1 and Table 3-2 set out the network tariffs within each tariff class for Energex and Ergon Energy. Assignment to individual network tariffs within these tariff classes are described in the tariff assignment sections in Chapter 4.2 (residential customers), Chapter 5.2 (small to medium business customers) and Chapter 6.1 (large business customers).

Energex

We are satisfied that Energex's tariff classes contribute to achievement of compliance with the distribution pricing principles.

Customers with similar load and connection characteristics are grouped together within a tariff class. There may be multiple tariffs within a tariff class that customers can be assigned to. Energex's tariff classes are set out in Table 3-1. We approve these tariff classes, which are consistent with the tariff classes Energex has applied in the past and are similar to those adopted in other jurisdictions. We are satisfied Energex's tariff classes contribute to the achievement of compliance with the distribution pricing principles and other applicable requirements in the Rules, namely the Energex distribution determination.[50]

Table 3-1 Energex tariff class description

Customer Group	Description
Standard Asset Customers (SAC)	Customers connected to the low voltage network. Charges are average based shared network assets. Residential and small business customers are part of this class.
Connection Asset Customers (CAC)	Customers connected at the 11kV network. Large commercial and some industrial customers.
Individually Calculated Customers (ICC)	Customers connected at high voltages, 33kV or 110kV. An 11kV customer may be in this class if that customer also has electricity consumption exceeding 40Gwh per annum and/or Customer has demand equal to or exceeding 10MVA Tariffs are based on actual dedicated connection assets for each customer

[50] AER, Final decision, *Energex determination 2015–16 to 2019–20*, Attachment 14 – Control mechanisms, appendix D, October 2015.

	and customers portion of the shared network utilised for electricity supply

Source: Energex.

Within each tariff class are a number of different tariffs, with customers assigned to each tariff based on their usage and connection characteristics. There are a total of 15 tariffs in the SAC class, across both residential and business customers. The CAC class has five tariffs, applicable to business customers only, and the ICC class. Tariffs for ICC customers are calculated on a site specific basis and are confidential to each recipient. There were no specific comments from stakeholders about tariff classes.

Ergon Energy

We are satisfied that Ergon Energy's tariff classes contribute to achievement of compliance with the distribution pricing principles and other applicable requirements in the Rules, namely the Ergon Energy distribution determination.[51]

Ergon Energy's tariff classes are set out in Table 3-2; within each tariff class are a number of different tariffs, with customers assigned to each tariff based on their usage and connection characteristics. This is consistent with Ergon Energy's past practice and represents no change from its historic tariff classes or practice of assigning and reassigning customers. It is also comparable to that of other jurisdictions. There were no specific comments from stakeholders about tariff classes.

Table 3-2 Ergon Energy tariff class description

Tariff class	Customer description
Standard Asset Customers (SAC)	Annual consumption below 4GWh including customers with micro-generation facilities. The SAC group is further subdivided into network tariff categories: metered or unmetered; residential or business use; high voltage or low voltage; consumption above or below 100MWh p.a.; meter capable of recording demand; supply capable of being controlled by Ergon Energy.
Connection Asset Customers (CAC)	Annual consumption typically greater than 4 GWh but less than 40 GWh. Requires capacity above 1,500 kVA or below 1,500kVA where the supply is quite different and would result in inequitable treatment of comparable customers. The CAC group is further subdivided into voltage level categories: 66 kV; 33 kV; 22/11 kV Bus; 22/11 kV Line.
Individually Calculated Customers (ICC)	Annual consumption typically greater than 40 GWh. Customers with annual consumption less than 40 GWh where the dedicated supply system is quite different and separate from the remainder of the supply network; few customers in a supply system making average prices inappropriate; connection is close to a Transmission Connection Point; or inequitable treatment of otherwise comparable customers.

51 AER, Final decision, *Ergon Energy determination 2015–16 to 2019–20*, Attachment 14 – Control mechanisms, Appendix D, October 2015.

Source: Ergon Energy.

3.1 Standalone and avoidable costs

We approve Energex and Ergon Energy's recovery of cost within each of their tariff classes. We are satisfied that for each tariff class, the revenue expected to be recovered lies between;

- the stand alone costs of serving the retail customers who belong to that tariff class; and
- the avoidable cost of not serving those retail customers.

We consider this contributes to the achievement of compliance with the distribution pricing principle 6.18.5(e).

The stand alone cost for a tariff class is the cost of supplying the electricity network service to only the tariff class concerned, with all other tariff classes not being supplied. If customers were to pay above the stand-alone cost, then it would be economically beneficial for customers to switch to an alternative provider. It would also be economically feasible for an alternative service provider to operate. This creates the possibility of inefficient bypass of the existing infrastructure.

The avoidable cost for a tariff class is the reduction in network cost that would take place if the tariff class were not supplied (whilst all other tariff classes remained supplied). If customers were to be charged below the avoidable cost, it would be economically beneficial for the business to stop supplying the customers as the associated costs would exceed the revenue obtained from the customer.

In setting network tariffs, Energex and Ergon Energy must comply with the distribution pricing principles, which includes ensuring that there are no cross subsidies between tariff classes. For each tariff class, expected revenue to be recovered from customers must lie between the standalone cost of serving those customers and the avoidable cost of not serving those customers.[52] This prevents large cross subsidies between tariff classes, such as residential and large business customers.

Energex and Ergon Energy have both provided estimates of the standalone and avoidable costs of serving their customers within each tariff class and explained their approaches to estimating these costs. For these initial tariff structure statements we have assessed whether the expected revenue within each tariff class lies between the standalone and avoidable costs of serving customers within that tariff class. As these initial tariff structure statements are being assessed within a regulatory period we have not reviewed the distributors underlying methodologies for calculating these costs in detail. For future tariff structure statements we are likely to assess in more detail the underlying methodologies of calculating the avoidable and standalone costs. We do

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

note however that these methodologies have been applied by Australian distributors for many years and so remain consistent with previous practice.

Table 3-3 and Table 3-4 compare Energex and Ergon Energy's estimates of the expected revenue from each tariff class to the avoidable and standalone costs of supply. These tables show that the avoidable cost is lower than the DUOS revenue recovered for each tariff class. The standalone cost is greater than the revenue recovered for each tariff class.

As the expected revenue for each tariff class for Energex and Ergon Energy lies within the lower bound of the avoidable cost and the upper bound of the standalone cost, the distributors have complied with clause 6.18.5(e) of the Rules.

Table 3-3 Energex estimates of avoidable cost, expected revenue and stand alone cost by tariff class FY2017–18

Tariff class	Avoidable cost	Expected revenue	Stand alone cost
ICC	$12,624,194	$38,714,906	$64,644,571
CAC	$13,911,464	$121,563,351	$213,082,599
SAC	$56,943,974	$1,284,761,223	$1,407,756,761

Source: Energex, Tariff Structure Statement October 2016, p.7

Table 3-4 Ergon Energy estimates of avoidable cost, expected revenue and stand alone cost by tariff class, 2017–18

Tariff class	Avoidable costs	Expected revenue	Stand-alone costs	Clause 6.18.5(a) met
Individually Calculated Customer – East	$19,156,275	$36,902,815	$248,991,729	Yes
Individually Calculated Customer – West	$1,872,647	$12,823,963	$28,554,472	Yes
Individually Calculated Customer – Mount Isa	$0	$0	$0	Yes
Connection Asset Customer – East	$25,789,802	$75,438,508	$270,188,778	Yes
Connection Asset Customer – West	$325,427	$10,852,333	$26,889,429	Yes
Connection Asset Customer – Mount Isa	$0	$0	$0	Yes
Standard Asset Customer – Large – East	$183,823,121	$290,358,587	$982,544,246	Yes
Standard Asset Customer – Large – West	$48,717,599	$79,984,792	$263,129,540	Yes
Standard Asset Customer – Large – Mount Isa	$3,729,027	$4,241,260	$13,328,248	Yes
Standard Asset Customer – Small – East	$310,670,425	$630,030,791	$982,544,246	Yes
Standard Asset Customer – Small – West	$99,404,889	$175,896,889	$263,129,540	Yes
Standard Asset Customer – Small – Mount Isa	$6,072,815	$9,876,238	$13,328,248	Yes
Standard Asset Customer – Unmetered – East	$6,927,630	$18,985,074	$570,944,159	Yes
Standard Asset Customer – Unmetered – West	$1,855,249	$2,550,344	$26,670,805	Yes
Standard Asset Customer – Unmetered – Mount Isa	$94,552	$276,119	$718,902	Yes

Source: Ergon Energy, Revised Tariff Structure Statement October 2016, pp. 106-107

4 Residential customer tariffs

This chapter sets out our assessment of the Queensland distributors' proposed tariff structures, including tariff design and charging windows.

Our final decision for Energex is:

- Approval opt-in demand tariffs for residential customers
- Approve the peak charging window for residential customer tariffs (see chapter 8 for further discussion).

Customers can opt-in to these tariffs and then choose to opt back out if they wish. The flat tariff is the default tariff for residential customers. Energex presently is advised by retailers if a customer is a new customer or an existing customer for tariff assignment purposes. New customers are those recently connecting to the distribution network, for example in newly constructed housing estates, or those who upgrade to a smart meter.

This is the same outcome as the draft decision. It also represents no change from Energex's initial tariff structure statement proposal to its revised tariff structure statement proposal.

Our final decision for Ergon Energy is:

- Approve the introduction of seasonal time of use energy and seasonal time of use demand tariffs, on an opt-in basis.
- Permit the development of a mandatory assignment, with an opt-out provision, to seasonal time of use energy or seasonal time of use demand charge for new small customers from 1 July 2018. This will be dependent on the type of meter installed at a customer's premises from 1 December 2017.
- Approve the peak charging windows set out in the revised tariff structure statements for residential customers.

The inclining block tariff is the default tariff for existing residential and small-medium business customers. Customers can opt-in to the seasonal time varying and seasonal demand tariffs. They can then opt-out to the default inclining block tariff if they wish.

In 2017–18, for a new customer the inclining block tariff is the default tariff. They may opt-in to the time varying and demand tariffs. From 2018–19 new customers will be on the demand tariff by default but can opt-in to the inclining block tariff or the time varying tariff.

This is the same outcome as the draft decision. It also represents no change from Ergon Energy's initial tariff structure statement proposal to its revised tariff structure statement proposal.

In recent years, the increased penetration of air-conditioning has caused peak demands to increase but there has been an easing of this trend. However demand has remained high, even if total energy consumption (kWh) has fallen.

Peak demand growth, or sustained high levels of demand, has resulted in networks needing to spend capital to augment their infrastructure to ensure demand can be met. If this is not done, there is the possibility of network outages and reducing reliability to customers.

We consider that demand charges will send signals to customers about their use of the network at times when the network is more likely to be most stressed. This will provide an incentive for customers to reduce their demand on the network. Signals to this effect over time can reduce peak demand, reducing the need for future investment upgrades, which represents a saving for all electricity customers.

Additionally, new technological development can be positively impacted by demand tariffs. For instance, battery storage is anticipated to become more prevalent in future. Customers with solar PV system will be able to store electricity generated during the day in the battery, and consume from the battery in the evening when peak charges are highest. By doing so, these customers will lower their demand, avoiding the peak tariffs, and likely reduce overall network demand too.

4.1 Tariff design

Energex

We approve Energex's new opt-in time of use energy and time of use demand charges. We consider these contribute to achievement of compliance with the distribution pricing principles. This is because a time of use or demand tariff is more cost reflective than flat or inclining block tariffs that focus only on energy consumption. These tariffs do not price demand and do less to incentivise customers to reduce their peak demand. This demand tariff will comprise:

- A fixed supply charge in $/day
- A peak demand charge in $/kW/month from 4pm to 8pm, weekdays only, and excluding public holidays. Peak demand will be measured via a single half hour interval within the monthly billing period
    - For the first 12 months, eligible customers' chargeable demand will be capped at a maximum of 5kW in any given month (although customers can choose not to be involved in this capping scheme)
- A flat energy usage charge, in kWh, over the billing period.[53]

Retailers who face this tariff will need to ensure that their end use customer has an advanced interval meter capable of recording kW.

Customers can opt-in to these tariffs and then choose to opt back out if they wish. The default tariff for existing residential and new residential customers is the residential flat tariff.

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53 Energex, *Tariff Structure Statement 1 July 2017 to 30 June 2020*, 4 October 2016, pp. 22-23.

Energex will also offer controlled load tariffs–called smart control–to residential customers who have a type 4 meter (i.e. smart meter) and who are also assigned to the above mentioned demand tariff. This secondary load tariff enables customers with loads that Energex controls—such as electric hot water heating—to receive a discounted tariff during the period that the load is being controlled. It acts like a demand management device and helps mitigate localised network demand pressures.

The existing legacy tariffs–a flat tariff with energy only charges and a time of use energy charge that has peak, shoulder and off peak rates—remain available. This is the tariff to which retailers will likely assign most of their residential customers initially, unless those customers actively choose the demand tariff.

Our draft decision approved the opt-in demand tariff and the continuation of the default energy only flat tariff. We considered this a reasonable transition to cost reflective tariffs and that the proposed suite of tariffs complied with the distribution pricing principles.

We did not receive further submission from stakeholders on Energex's residential tariff design.

We have approved the new cost reflective network tariffs for residential customers. We consider that these contribute to achievement of compliance with the distribution pricing principles. Demand is the key driver of additional capital expenditure for the Energex distribution network. Tariffs that target peak (maximum) demand (measured either in kW or kVA) are considered more cost reflective than those that do not. This is especially compared to flat rate tariffs, which have the same charge (usually measured in kWh) throughout the entire billing period and so do not signal times of peak demand

For Energex, the peak demand period is from 4pm to 8pm weekdays. Outside of these hours, a cheaper off peak demand tariff will apply. Customers who consume electricity during peak times will place most stress on the network and are more likely to generate higher peaks, requiring capital augmentation to meet potential future network constraints. More discussion on the charging windows can be found in Chapter 8.

Ergon Energy

We approve Ergon Energy's new opt-in seasonal time of use energy and seasonal time of use demand charges. We consider these contribute to achievement of compliance with the distribution pricing principles. This is because a time of use or demand tariff is more cost reflective than flat or inclining block tariffs that focus only on energy consumption. These tariffs do not price demand and do less to incentivise customers to reduce their peak demand.

Opt-in seasonal time of use energy (STOUE) and a seasonal time of use demand (STOUD) tariffs have been proposed. The peak charging windows send signals to energy retailers about their use of the network at times when the network is more likely to be facing maximum demand. This will signal the need for potential future augmentation to ensure that demand can continue to be met.

Energy retailers will then be incentivised to offer retail tariffs to customers that align with these incentives. Alternatively, energy retailers may choose to continue offering a flat rate tariff, but with a higher charge to compensate for the additional risk the retailer faces in bearing the demand charge for relevant end use customers.

Submitters were supportive of the need for new cost reflective tariffs. The Clean Energy Council, retailers and the Energy Networks Association all considered that cost reflective tariffs were appropriate.[54]

We approve Ergon Energy's STOUE and STOUD tariffs for residential customers. This is because these tariffs will be opt-in, enabling an informed customer choice about whether this tariff is suitable or not for their circumstances. The existing legacy three step inclining block tariffs that existed prior to the tariff structure statement proposal will remain. This tariff structure was first introduced in 2014. These tariffs will be the default to which retail customers will be assigned, unless the customer's retailer chooses the STOUE or STOUD.[55]

In the draft decision, we approved the seasonal time of use energy and seasonal time of use demand tariffs for residential customers to be provided on an opt-in basis. Only Canegrowers disputed that these tariffs were appropriate. They considered that residential and irrigation business customers were not contributing to demand or congestion on the Ergon Energy network.

We consider that Canegrowers is proposing pricing for the irrigation sector that is more locational in design than Ergon Energy's current and proposed tariffs. They note that there may be parts of the network where demand is not high at times when demand is high for the network as a whole. They argue that customers on these parts of the network should be charged less at peak times than other customers. This concept of locational pricing may be introduced into Australian distribution pricing in future. However, at present, there is no granular location based network pricing in the national electricity market, other than the broad geographical application of tariffs within distribution areas. That is, no distributor has specific tariffs for a sub-segment of customers within a tariff class, such that their tariff varies from that of other customers within that tariff class. It may be that this occurs in future as more sophisticated tariff options are developed, however it is not yet available within Queensland. Moreover, Queensland's uniform tariff policy means that Ergon Energy's network costs are not directly passed through to customers, who instead see Energex's (lower) charges. This means the full price signal is not being incorporated into the retail tariffs faced by rural and regional customers. As such, end use customers may not directly see the Ergon Energy price signal.

Additionally, one important element of the electricity network charging regime is that all customers within a particular tariff class will bear the costs associated with network

[54] Clean Energy Council, *Submission to AER on SA, ACT, NSW and QLD tariff structure statements,* 26 October 2016.

[55] Ergon Energy, *Revised tariff structure statement 2017 to 2020*, October 2015, p. 24.

augmentation investments made to supply that tariff class. It can be the case that not all customers within a tariff class may have directly contributed to the need for an investment upgrade or may have contributed to differing extents. Nevertheless, network tariffs within a tariff class are "averaged" such that all users within the tariff class share in the costs associated with serving that class of customer. This is the case even where a certain group of customers within a tariff class may not have, through their actions, directly caused the need for the network augmentation upgrade.

It follows that peak prices will be the same for all customers within a particular tariff class where the relevant tariff in question is available to those customers.[56] Put another way, there is at present little or no basis for charging a specified group of customers a different tariff where they use the network at the same time as other customers who have similar (if not the same) usage profile and connection characteristics. There may be a case for offering a different tariff to customers whose characteristics are sufficiently different to other customers and this is something that Ergon Energy should give consideration to for future tariff structure statements. Ergon Energy's distribution determination sets out the procedures governing assignment and reassignment of customers to tariff classes. Customers of a specified class are not to be charged a different tariff if their connection characteristics and load profile are similar.[57]

Canegrowers submission recommends that the STOUD tariff could be made more cost reflective by setting the peak demand based on four network system peaks rather than four individual customer peaks, and providing notification of the peaks a day ahead. We have responded to this in Ergon Energy's small to medium business customer tariffs in Chapter 5.1.

We therefore regard Ergon Energy's use of customer peaks rather than network peaks for charging purposes, as contributing to compliance with the distribution pricing principles.

4.2 Tariff assignment

We approve the tariff assignment and reassignment methodologies set out by both Queensland distributors. These have not changed in any fundamental way from previous years, or from their initial tariff structure statement proposals. We are satisfied these methodologies contribute to the achievement of compliance with the distribution pricing principles and other applicable requirements of the Rules.

Energex

We approve Energex's tariff assignment and reassignment methodologies for residential customers.

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56 AER, Final decision, *Ergon Energy determination 2015–16 to 2019–20*, Attachment 14 – Control mechanisms, Appendix D, October 2015

57 AER, Final decision, *Ergon Energy determination 2015–16 to 2019–20*, Attachment 14 – Control mechanisms, Appendix D, October 2015.

Energex groups its residential customers into the standard asset customer class. This class receives a share of all assets that are utilised by low voltage customers.

Energex's revised tariff structure statement (October 2016) continues the theme from its initial tariff structure statement in November 2015 of moving residential customers onto cost reflective tariffs via active retailer or customer choice. That is, these customers will be able to opt-in to the new demand tariffs. They can also opt-in to the time of use tariff. The flat rate tariff is the default to which existing and new connection customers and will be assigned in the first instance.

This opt-in arrangement will apply to existing customers already connected to electricity network and to any new customers from 1 July 2017. The latter will be automatically assigned to the existing legacy tariff, being the flat rate tariff, or the time of use tariff. Customers have generally been supportive of opt-in arrangements. Origin Energy considers this is important to ensure a balance between cost reflective tariffs and simplicity. It is mindful that customers can understand new tariffs.[58]

Residential customers will continue to have the option of choosing between the flat tariff, the time of use tariff and the demand tariff during 2017–20. Energex does flag its intention to consult on whether the demand tariff should be mandatory post-2020.[59] We encourage that consultative approach and that mandatory or opt-out tariff assignments will progress tariff reform more quickly than opt-in approaches. Energex will also consider whether the legacy flat tariff and/or the time of use tariff should be closed to new entrants.[60]

We observed in the draft decision that interval meter take up by Queensland small customers is relatively limited to date. End use customer awareness of network tariff reform is also likely minimal. In the draft decision we noted that stakeholder submissions in response to Energex (and Ergon Energy's) tariff structure statements were overwhelmingly in favour of the proposed opt–in arrangements.[61]

We are satisfied that Energex's assignment and re-assignment of customers to tariff classes and tariffs is appropriate and in compliance with the distribution pricing principles. We consider this approach:

- Provides an opportunity for customers making new investments to opt for a cost reflective tariff which may prove beneficial to them compared to their existing tariffs.

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58 Origin Energy, *AER Draft Decision on Queensland Tariff Structure Statements*, 4 October 2016, p. 1.

59 Energex, *Tariff Structure Statement–Explanatory notes, 1 July 2017 to 30 June 2020*, 4 October 2016, p. 43.

60 Energex, *Tariff Structure Statement–Explanatory notes, 1 July 2017 to 30 June 2020*, 4 October 2016, p. 41, table 5.7.

61 AER, *Queensland Tariff Structure Statement Draft Decision*, August 2016, p.p. 37-38. See also National Seniors Australia, *Tariff Structure Statement proposals - Queensland electricity distribution network service providers*, April 2016, p. 2; Energy Consumers Association, *QLD electricity distribution networks' Tariff Structure Statements Submission to the Australian Energy Regulat*or, May 2016, pp. 5–6; AGL, *Re: Tariff Structure Statement proposals of the Queensland electricity distribution network service providers*, April 2016, p. 2.

- An opt-in approach gives customers more time to better understand their electricity usage patterns before transitioning to a demand tariff or some other form of cost reflective tariff.
- Enables retailers time to implement their own internal systems in order to give consideration to:
  - passing through to end use customers the network demand tariff
  - package the network tariff in a form that retailers consider will aid customer understanding and behavioural response

In light of the distribution pricing principles reference to transition periods[62], we consider that opt-in assignment policies are suitable for this first round of tariff reform. They are likely to achieve a degree of market and customer acceptance that a mandatory assignment might not.

However, we note reliance on opt-in arrangements may not be appropriate into the future, and that networks should consider as part of their consultation for the 2020 tariff statements approaches that would result in faster transitions to cost reflective pricing. For the 2020–25 tariff structure statement, we observe Energex's intent to consult stakeholders about transitioning customers more quickly to cost reflective tariffs.

Our discussion in the future directions section of this final decision may assist the distributor in its customer engagements. We support the approach that Energex is taking to help transition customers to more cost reflective pricing, including the impact this may have on certain customer types. We also observe that much will depend on how retailers decide to package distributors' network tariffs into a final retail tariff offer for customers. This will influence to some degree the extent to which an end use customer may make behavioural changes in their electricity demand and consumption decisions.

Ergon Energy

Residential customers are assigned to Ergon Energy's standard asset class. During the 2017–2020 period, Ergon Energy will assign existing customers to the STOUE or STOUD tariffs on an opt-in only basis. That is, energy retailers whose customers have the relevant metering technology will have the discretion to take up these tariffs. Alternatively, they can stay on the legacy inclining block tariff to which residential customers are currently automatically assigned.

In the draft decision we noted that stakeholder submissions in response to Energex and Ergon Energy's tariff structure statements were overwhelmingly in favour of the proposed opt–in arrangements.[63]

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

[63] AER, *Queensland Tariff Structure Statement Draft Decision*, August 2016, p.p. 37-38. See also National Seniors Australia, *Tariff Structure Statement proposals - Queensland electricity distribution network service providers*, April 2016, p. 2; Energy Consumers Association, *QLD electricity distribution networks' Tariff Structure Statements*

New connection customers (residential and business, who have a smart meter) will be automatically assigned to the seasonal time of use demand tariff but with an opt-out provision from July 2018. Customers who upgrade their meter from 1 December 2017 will also be assigned to this demand tariff. We support this approach. It is aligned with ensuring that any new customer connecting to the Ergon Energy distribution network will face the most cost reflective prices. It also ensures that some customers will be on the demand tariff (noting that current customers have the choice to opt-in to this tariff), providing the distributor with information about the effectiveness of this tariff and enabling any refinements to be considered for future tariff structure statements.

The tariff assignment and reassignment provisions are spelt out by Ergon Energy at appendix D of its revised tariff structure statement. That appendix goes into a lengthy discussion of the reasons for why a customer might be reassigned and the circumstances under which the reassignment will occur. The mechanism for a customer to object to an assignment or reassignment is also set out.

We find that the information set out by Ergon Energy on assignment and reassignment is consistent with the requirements in the National Electricity Rules, Ergon Energy's distribution determination and further represents the long standing approach adopted by Ergon Energy over many years. That approach remains relevant for the current tariff structure statement period as thus is approved.

4.3 Future direction

In these final decisions, we accepted the use of opt-in assignment policies in moving customers to cost reflective tariffs for this first round of tariff structure statements. However, we also observe that sole reliance on opt-in arrangements may not be appropriate into the future for the reasons outlined in the overview section of this decision. Networks should consider this as part of their consultation for the 2019 and beyond tariff structure statements.

An opt-in approach to tariff assignment is at one end of the spectrum of possible approaches, including:

- assigning customers to a cost reflective tariff (subject to appropriate metering) by default but allowing opt–out provisions
- leaving existing customers on current tariffs but assigning new customers to cost reflective tariffs (subject to appropriate metering) and allowing opt–out provisions
- mandatorily assigning customers to cost reflective tariffs wherever appropriate metering is available (with no opt-out provisions).

Our current view is that, for the next round of tariff structure statements, default assignment to cost reflective tariffs with opt-out provisions should be adopted over opt-

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*Submission to the Australian Energy Regulat*or, May 2016, pp. 5–6; AGL, *Re: Tariff Structure Statement proposals of the Queensland electricity distribution network service providers*, April 2016, p. 2.

in arrangements as it would better contribute to compliance with the distribution pricing principles by providing more appropriate price signals to retailers. Each tariff structure statement should show movement towards more cost reflective tariffs, taking into account of possible customer impacts.[64] We are also open to considering mandatory tariff assignment arrangement proposals (i.e. no opt-out provisions), as long as distributors have addressed the customer impact principle in the Rules.

In the next round of tariff reform we consider new customers across all networks should be assigned by default to cost reflective tariffs.[65] By 'new' customer, we mean customers in new premises who are connecting their premise to the network for the first time. This is because:

- After 1 December 2017, newly connected premises must have a smart meter installed—this means these customers will have meters which are capable of calculating cost reflective network tariffs.[66]
- These customers are also at a point where they are about to make new investment decisions and they should make these decisions on the basis of cost reflective network tariffs—these decisions may include the energy efficiency of their building design, whether they install solar PV or batteries in their new home or office, and decisions over any new appliances they are buying as part of moving to a new premise.
- Alignment with the metering contestability rule change also means that this change occurs in an environment where the meter is provided by or through a customer's retailer on a competitive basis. The meter will no longer be a regulated service provided by the distributor. While the Rules prescribe minimum functional requirements for these meters, retailers can also offer customers smart meters with a range of other additional features. The installation of smart meters by retailers may increase the range of services and pricing options that are available to consumers, and therefore help consumers respond to retail packages that incorporate the new network tariffs.[67]

On the other hand, existing customers may have made significant investments on the basis of current tariff structures. Further, many existing customers (outside of Victoria) may not have appropriate metering technology in place to enable uptake of more cost reflective network tariff options. However, for existing customers, there are two approaches we consider meet the need to move customers onto cost reflective network tariffs[68] while balancing the customer impact[69] considerations. We encourage

[64] NER, cl. 6.18.5(e) – (h).
[65] NER, cl. 6.18.5(c).
[66] Australian Energy Market Commission, *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015,* November 2015.
[67] NER, cl. 6.18.5(h).
[68] NER, cl. 6.18.5(c).
[69] NER, cl.6.18.5(h).

distributors to focus on either or both of these approaches. These two approaches are outlined below.

Firstly, for existing customers making significant new investments we consider these customers could be assigned by default to cost reflective network tariffs. This approach should be technology neutral—for example, we did not approve SAPN's proposed 'solar tariff'.[70] We consider the time of making new investments is a good time to transition customers to cost reflective tariffs. This approach gives customers the opportunity to consider their new investment with regard to the implications of the new tariff they will be assigned—that is, the network cost implications of their usage.[71] Significant new investments may include:

- change from single to three phase connection
- new solar photovoltaic connection
- new battery
- new electric vehicle.

Some of these upgrades are identifiable to distributors; others may require additional reporting arrangements.[72]

In moving to default assignment to cost reflective tariffs in the next tariff structure statement period, distributors are required to address the customer impact provisions of the Rules.[73] One option suggested by SAPN, would be to assign residential and small business customers (with smart meters) to a cost reflective tariff only after at least one or two years of interval metering data is available.[74] Our preliminary view is that we are open to this approach as we expect it would enable the end customer to make more informed decisions over what retail offer they choose because they would have a better understanding of their current consumption patterns.

Secondly, for existing customers who remain on flat rate or block tariffs, we consider the relative levels of these network tariffs compared to more cost reflective tariff options could be increased. This is to encourage customers to choose retail offerings which voluntarily opt-in to cost reflective network tariffs.

In our view all customers should eventually be on cost reflective tariffs as this will provide more appropriate pricing signals to retailers. By cost reflective network tariffs we mean network tariffs which incorporate higher charges during times of network congestion and lower charges during times when the network is not congested. Demand and time-of-use tariffs are examples of tariffs with this feature. In contrast, we consider flat rate, inclining block or declining block network tariffs are not cost

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70 See our draft decision on SAPN's proposed solar tariff.

71 NER, cl.6.18.5(h).

72 i.e. SAPN has used the change from single to three phase and the installation of a new inverter as a trigger for reassignment to cost reflective tariffs.

73 NER, cl.6.18.5(h).

74 SAPN, *Revised tariff structure statement proposal – part B*, October 2016, p. 123.

reflective. This is because the charges under these tariffs are unrelated to times of network congestion.

Emerging technologies—batteries and electric vehicles

In the near future some consumers may change their pattern of use by installing battery storage at their premises. The low but increasing popularity of electric vehicles may also have an impact on the grid. If the incentives are right, with appropriate pricing signals, battery storage and electric vehicle adoption could bring many benefits to the electricity network. They have the potential to help manage peak demand, reducing the need to grow the network, ultimately relieving pressure on electricity prices. On the other hand, if the incentives are not right, the increase in batteries and electric vehicles could lead to inefficient investments—both by the network and end customers—with these inefficient costs paid for by end customers.

Customers with batteries and electric vehicles are likely to be beneficiaries of cost reflective tariffs. Even without opt-out arrangements, it is possible these customers may opt-in by choosing retail tariffs based on cost reflective network tariffs. This is because batteries and electric vehicles have the capacity to store energy at off-peak times and inject energy at peak times—this could assist in reducing a household's use of electricity drawn from the grid at peak times.

It would be useful to monitor the extent to which customers with batteries and electric vehicles choose retail tariffs that are based on the more cost reflective network tariffs. If uptake is not forthcoming, changes to reporting arrangements may be desirable to make these customers identifiable to distributors. This could then be used as a basis for default tariff assignment to cost reflective network tariffs in the future if necessary.

We invite distributors and industry, as part of the development of the next phase of tariff structure statements, to consider whether triggers, such as the installation of electric vehicles and batteries should be considered for reassignment. Further:

- What impediments (if any) would need to be addressed to allow this to occur?
- Are additional changes required to incentivise customers to charge or discharge their batteries or electric vehicles at efficient times?

Even with the above changes, it is likely the speed of tariff reform will still be gradual. This is because it will depend on consumer and retailer driven factors, as only a proportion of customers over any given period will be have a new connection to the network or significantly change their connection. Nonetheless the pace of reform will likely be quicker than if chief reliance is placed on an opt-in only approach.

Tariff reform is a long term process. We consider the distribution pricing principles require movement towards more cost reflective tariffs with every tariff structure statement proposal over upcoming regulatory control periods.[75]

[75] NER, cl. 6.18.5(b) to (d).

5 Small to medium business customer tariffs

This chapter sets out our assessment of distributors' proposed tariff structures, including tariff design and charging windows.

Our final decision for Energex is:

- Approve opt-in demand tariffs for small to medium size business customers
- Approve a peak demand charging window of 9am to 9pm for all business customers

Our final decision for Ergon Energy is:

- Approve the introduction new seasonal time of use energy and seasonal time of use demand tariffs, on an opt-in basis.
- Approve the peak charging windows set out in the revised tariff structure statements for business customers.

5.1 Tariff design

Energex

We approve Energex’s suite of small to medium business customer tariffs as we are satisfied these tariffs contribute to the achievement of compliance with the distribution pricing principles. New demand tariffs for this tariff class are a step towards more cost reflective pricing and will incentivise customers to use the network at off-peak times where possible.

Tariffs that comprise fixed supply charges, usage charges, demand components and excess demand charges are features of Energex’s small to medium business tariffs. A flat tariff, a time of use tariff and a demand tariff will all be available to customers.

Small business tariffs have been calculated using that businesses single maximum half hour demand during the billing period, between 9am and 9pm on weekdays.

For large customers, an excess demand charge will also apply, to encourage them to reduce their demands or shift their demand to off-peak periods.

In the draft decision we accepted these tariffs as contributing to the achievement of compliance with the distribution pricing principles.

There were no specific stakeholder comments about Energex’s suite of small to medium business customer tariffs, with the exception of the Local Government Association of Queensland. The Association considered that its members would need time to adjust to demand tariffs and that Energex (and Ergon Energy) should consult with local municipalities about how demand based tariffs would affect them. They suggested a 12 month delay before any new cost reflective tariff is charged to local municipalities.[76]

We concur that distributors should engage with their customers about tariff reform. Energex has been undertaking consultation and engagement as part of this round of tariff structure statements. This includes the types of tariffs to be introduced and potential customer impacts. Retailers will also have a role to play, given they are the primary customer contact point.

We consider that the demand tariffs are a step towards improved cost reflecting and signalling the impact of customer usage on the network. Energex has a suite of business tariffs that are available to its customers across tariff classes and this helps promote customer choice. We also consider the use of a 30 minute demand measurement period is appropriate for this first round of tariff structure statements. Nevertheless, Energex could give consideration to adopting an average of a customer's top demands within the billing period to measure chargeable demand for future tariff structure statement periods. This is notwithstanding that retailers had advised Energex that they considered a single 30 minute period was simpler and easier for them to implement.[77]

It is not an individual customer's peak demand that drives network costs, but the extent to which that customer's peak demand contributes to network congestion and the network's co-incident demand. However, the network's co-incident demand may not be on the same day as an individual customer's highest demand. Ergon Energy's averaging approach for instance increases the probability that a customer's highest demand will coincide with the day, or days, on which the network's peak demand also occurs.

We encourage distributors to collect data during this first tariff structure statement period (2017–2020) that demonstrates if the majority of customers' peak demand occurs at the same time the network also experiences its peak demand. This should provide a useful basis for determining if the second and subsequent tariff structure statements should make a change to averaging a customer's highest demand days, similar to Ergon Energy's approach.

The use of a single period or averaging approach may also have an impact on a customer's ability to respond to price signals. Price signals aim to elicit an informed and considered response by customers. If a customer has automatic appliances (e.g. air-conditioner or battery storage is programmed to respond to peak demand periods), then responding to price signals might be straight forward. However, in the absence of automatic appliances, there is the potential for residential and small business customers' peak demand periods to occur more by accident than design. This is especially the case initially, as these customers gradually become more familiar with

[76] LGAQ, *Submission on AER draft decision Qld DNSPs Tariff Structure Statements 2017–20*, 4 October 2016, p.1, 2.

[77] Energex, *Tariff Structure Statement - Explanatory notes, 1 July 2017 to 30 June 2020*, 4 October 2016, p.p. A.8-9.

demand signals and the amount of electricity different appliances consume. If a customer's top 30 minute demand window occurs by accident in one month, they will have a heightened incentive to understand their electricity usage the following month to avoid a repeat situation. Alternatively, an averaging approach might assist a customer in responding within the month, rather than waiting until the next month. For similar reasons, an averaging approach may also assist a customer to avoid or manage large bill variations.

Notwithstanding these potential issues, we consider Energex's proposed approach of using a single 30 minute period adequately manages customer impacts and therefore is approved.

Ergon Energy

We approve Ergon Energy's suite of demand, time of use and inclining block tariffs for small and medium size business customers as we are satisfied these contribute to the achievement of compliance with the distribution pricing principles.

Customers in the small to medium business customer class – SAC-S, SAC-L, will continue to be automatically assigned to the inclining bock tariff.

Opt-in time of use energy (STOUE) and time of use demand tariffs (STOUD) will also be offered.

Ergon Energy's inclining block tariff is the default tariff for existing residential and small-medium business customers. Customers can opt-in to the seasonal time varying and seasonal demand tariffs. They can then opt-out to the default inclining block tariff if they wish. In 2017–18, for a new customer the inclining block tariff is the default tariff. They may opt-in to the time varying and demand tariffs. From 2018–19 new customers will be on the demand tariff by default but can opt-in to the inclining block tariff or the time varying tariff.

These tariffs reflect a demand component charged in $/kW/month and are designed to incentive business customers to limit their use of the Energex network when it is most likely to experience high levels of maximum demand.

The tariffs comprise a fix on fixed supply charges, energy charges and demand charge components.

We approved these as part of our draft decision, and Energex has resubmitted these as part of its revised tariff structure statement.

We continue to hold the view that these tariffs will contribute to achievement of compliance with the distribution pricing principles. This is because:

- Time of use and demand tariffs are more cost reflective than flat consumption only tariffs and are therefore an improvement in terms of delivering cost reflective pricing
- They appropriately signal the future investment costs associated with upgrading the distribution network

- Allow for a reasonable period of transition, though their opt-in nature and therefore allow a reasonable degree of choice for customers in tariff selection
- They reduce the extent of cross subsidies among customers both within a tariff class and between tariff classes, thus leading to more equitable pricing outcomes and less distortions in pricing signals.

Our decision is respect of approving Ergon Energy's the peak charging windows is set out in Chapter 8.

5.2 Tariff assignment

Energex

We approve Energex's policy to assign small and medium business customers to cost reflective tariffs on opt-in basis. We consider this contributes to achievement of compliance with the distribution pricing principles.

In our draft decision we approved Energex's opt-in assignment policies for small and medium business customers.

Energex will introduce a new demand tariff for LV customers with annual consumption of less than 100MWh will be opt-in from 1 July 2017.

Business flat tariff and business time of use will remain unchanged in their structure during 2017–20 compared to their current form.

We consider that these tariffs represent a move towards cost reflective pricing, offer customers a choice of tariff options and ensure that Energex has the ability to recover its efficient costs from business customers who use its network.

By including the option for its customers to choose between three different tariffs, with the business flat tariff being the default, Energex is cognisant of customer impact and is providing its customers with greater choice and ability to manage their demand, consumption ,and ultimately their bills. We consider this is consistent with distribution pricing principles.[78]

This is because it takes into account customer impacts by ensuring that small and medium size customers have time to better understand new demand tariffs—this might be through retailers' communication with them. In this way, the goal of tariff reform is progressively explained over time, lending itself to potentially more acceptance than one based on significant short term change.

In addition, we note the context in which Energex is making cost reflective business tariffs opt-in for the 2017–20 tariff structure statement period. It wishes to engage with retailers and other stakeholders on the outcome of its tariff studies and build a social licence for tariff reform. Post 2020, Energex has flagged an intent to move customers

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78 NER, cl 6.18.5(h)(3).

to cost reflective demand tariffs more quickly based on data from its tariff studies, the increased penetration of smart meters throughout the network (which enable demand based pricing) and commitment to reduce cross subsidies between tariff classes, and between individuals within tariff classes.[79]

We consider this staged approach to tariff reform appropriately accounts for customer impacts.

Ergon Energy

We approve Ergon Energy's opt-in seasonal time of use energy and opt-in seasonal time of use demand tariffs as we are satisfied these contribute to the achievement of compliance with the distribution pricing principles.

The cost reflective tariff will be opt-in for small to medium size businesses. They have a choice of the seasonal time of use energy, seasonal time of use demand or the inclining block tariff. The latter is the default tariff for customers within this tariff class.

The aim of cost reflective pricing is to provide signals to customers about the impact of their usage on the network. This is done by providing prices that signals future investment costs and permit recovery of residual (sunk) costs.

We do not consider an inclining block tariff to be as cost reflective as time varying or demand tariffs. That is because they are less effective at signalling when times of consumption relate to network demand pressures. Indeed, inclining block tariffs usually only measure energy in kWh, and not demand. These tariffs will likely incentivise customers with higher consumption levels to move to time varying tariffs or demand based tariffs, where the energy charge is much lower. In this respect, Ergon Energy is not intending for the inclining block tariff to offer an alternative to avoiding the cost reflective tariffs. This tariff's charges have nevertheless been adjusted closer to cost reflective levels (long run marginal costs) to ensure those customers who remain on it are not being as heavily cross subsidised as they may have been previously. We would encourage Ergon Energy to consider ways to transition existing and new customers to wards the cost reflective tariffs. This may mean closing the inclining block tariff to new customers at the 2020-25 tariff structure statement period.

Canegrowers were nonetheless concerned that the price of the seasonal time of use energy and seasonal time of use demand, along with the relative price of the inclining block tariff, did not permit proper customer choice. Specifically, they considered that the price of the inclining block tariff did not represent a "safe harbour" for customers because the third block was particularly expensive, and that Canegrowers members were likely to be in this third block of usage.[80] Ergon Energy's own small scale study showed that the irrigators were at the lower end of usage then the average business in

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79 Energex, Tariff Structure Statement - Explanatory notes, 1 July 2017 to 30 June 2020, 4 October 2016, p.p. 32-33.

80 Canegrowers – Sapere – *AER Draft Decision on Ergon Tariff Statement (plus revisions): Review and comments for Canegrowers,* November 2016, p. 5.

their class.[81] However, we do not consider that any particular tariff is meant to represent a "safe harbour" for customers.

We would expect that over time, Ergon Energy might make the inclining block tariffs less attractive relative to the newly established time of use and demand tariffs, as part of a longer term strategy to encourage customers to switch to more cost reflective tariffs. We support this approach by Ergon Energy and do not agree with Canegrowers that those tariffs have been set so as to penalise customers on an inclining block tariff.

The Canegrowers submissions express the view that irrigators and cane growers customers have not added to Ergon Energy's network peak demand in recent years. This appears to support location based pricing. At present, there is no location based network pricing in the national electricity market, other than the broad geographical application of tariffs within distribution areas. That is, no distributor has specific tariffs for a sub-segment of customers within a tariff class, such that their tariff varies from that of other customers within that tariff class. It may be that this occurs in future as more sophisticated tariff options are developed, however it is not yet available within Queensland. Moreover, Queensland's uniform tariff policy means that Ergon Energy's network costs are not directly passed through to customers. This means the full price signal is not being incorporated into the retail tariffs. As such, end use customers may not directly see the Ergon Energy price signal.

Critical peak pricing

It is the case that critical peak prices provide a better signal to address network congestion points. However, the Rules do not require such an approach and, rather, permit a distributor to propose the tariff structure that it considers most appropriately meets its needs and that is consistent with the pricing principles. The AER has a compliance role to determine if this is the case. We do not have a role to overrule the proposed method with an approach we consider is better. We find that the approach adopted by Ergon Energy of averaging customers four highest demands within a peak charging window contributes to achievement of compliance with the distribution pricing principles. Moreover, that Ergon Energy's approach to average the four highest customer demand within a monthly billing period to use as the basis of chargeable demand is one of the more innovative approaches to tariff reform. We support its application and consider that other distributors ought to consider doing the same in their future tariff structure statements.

Furthermore, in future tariff structure statements, we do support Canegrowers view that Ergon Energy might be able to consider critical peak pricing with advance notification to customers of a peak event. As for using network peaks in place of individual

[81] Ergon Energy – Energeia – *Application of the National Electricity Pricing Rules to Ergon's STOUE and STOUD tariffs* – December 2016, p. 4.

customer peaks, we do note that other distributors have applied customer peaks as the means to measuring the level of peak demand.[82]

Canegrowers submission recommends that the STOUD tariff could be made more cost reflective by setting the peak demand based on four network system peaks rather than four individual customer peaks, and providing notification of the peaks a day ahead. Effectively, Canegrowers are suggesting a critical peak price be applied to STOUD customers.

As noted above, irrespective of their actual demand, all existing and future customers of a distribution network should face the cost of incremental investment necessary to meet demand. As such, we agree with Ergon Energy's view that peak charges should still apply to customers to signal the costs of future investment needs.[83] However, we consider that Canegrowers have made a valid point about future cost reflective pricing that could be implemented to fine tune these price signals and that this is something all distributors, not just Ergon Energy, should consider for future tariff structure statements.

5.3 Future direction

This is discussed in the future directions section 4.3.

[82] See for instance, the approach adopted by the Victorian electricity distribution service providers in their 2017–20 tariff structure statements. These are available on the AER's website.

[83] Ergon Energy – Frontier Economics – *Response to Sapere claims on Ergon Energy's Tariff Structure Statement* – December 2016, p. 8.

6 Large business customer tariffs

This chapter sets out our assessment of Queensland distributors' proposed tariff structures, including tariff design and charging windows.

Our final decision for Energex is:

- Approve the tariff classes applicable to large business customers
- Approve the new time of use demand tariff for standard asset customers-large, to commence from July 2018.

Our final decision for Ergon Energy is:

- Approve amendments to the excess reactive power charge, kVAr, such that load side generation will not incur the reactive power charge for intermittent generation on start up.
- In all other respect, approve the tariff classes applicable to large business customers.

We consider the demand and excess demand charges proposed by the Queensland distributors' tariffs are cost reflective because they are based upon the cost of providing capacity to meet customers' demand. They signal to customers the times when peak demand constrains network capacity. These price signals can also be effective demand management tools. Therefore, we are satisfied that both Energex and Ergon Energy's proposals contribute to the achievement of compliance with the distribution pricing principles.

6.1 Tariff design and assignment

Energex

An opt-in cost reflective demand charge, demand time of use 11kv, will commence from July 2017. This tariff includes fixed usage charge, variable energy charges, a demand charge (in$/kVA/month) and an excess demand charge ($/kVA/month).

Otherwise, large business customers' tariffs are not changing during the 2017–20 period. These tariffs are already set on a more cost reflective basis.

Large users are assigned to the individually calculated customers (ICC) tariff class where they are connected at the 110kV or 33kV distribution network. Energex has assets solely dedicated to these particular customers. It therefore charges them a site specific tariff, such that costs are directly attributable to individual users, rather than averaged across all network users as per the standard asset customer tariff class. Embedded generators will also be subject to this tariff.

Origin Energy submitted that embedded generators should not pay for distribution use of system charges for the export and import of electricity. Origin sought clarity about how Energex and Ergon Energy would apply the tariffs. Origin's concern was that both distributors' tariff structure statements seemed to indicate that embedded generators who are not retail customers would still face distribution use of system charges even when they did import (i.e. draw load) from the distribution network.[84]

Origin Energy provided us an email clarifying their original submission following our request for further explanation. Origin Energy also supplied supporting information from the Australian Energy Market Operator (AEMO) clarifying that one of their generators satisfies the above criteria.

We also discussed this issue with Ergon Energy.[85] We understand that both Ergon Energy and Origin have been in discussion on this issue for some time.

Following our discussion with the respective parties, it became apparent that the issue raised was about whether Origin's Roma power station has a load attached to it or not.

Clause 6.1.4 of the Rules is correctly referenced by Origin Energy as only permitting a distributor to levy distribution use of system charges on generators who net import energy from the grid into their premises. Net exporting energy into the grid will not incur these charges.[86]

However, we are not in a positon to determine if there is a load attached to this power station or not. That is for the two parties to determine through connection agreement negotiations, which they are presently involved in.

In the Rules, the broad principle is that if a generator is compliant with AEMO guidelines in respect to generator registration, it will be classified as a market load and will not have to pay distribution use of system charges.

However, if the generator has a load at the site for any purpose other than for the generation of electricity to be sold to the national electricity market and so is not covered by the applicable AEMO guidelines, then the load should face distribution use of system charges.

As the particular case between Origin Energy and Ergon Energy is a customer specific issue and can be resolved through negotiation between the parties, or dispute resolution.

We consider the tariff structure statements are not the framework for attempting to resolve site specific issues such as this. This is because a attempting to resolve site specific issues risks applying an approach to a site specific issue across the board that has unintended consequences for other customers.

In respect of tariff assignment and reassignment policies for large customers, our draft decision approved Energex's approach of automatic assignment to demand and

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84 Origin Energy, *AER Draft Decision on Queensland Tariff Structure Statements*, 4 October 2016, p.p. 1-2.

85 AER and Origin Energy, *staff telephone conversation*, 8 February 2017.

86 Note that NER cl. 6.1.4 does permit a distributor to impose a connection charge on a generator.

excess demand tariffs. We did not receive any comments from stakeholders on the revised proposal, which accepted our draft decision.

Our final decision is to approve the automatic assignment of large customers to demand and excess demand tariffs associated with the individually calculated customer class.

Ergon Energy

We approve Ergon Energy's suite of large customer tariffs as contributing to the achievement of compliance with the distribution pricing principles. Nevertheless, we require Ergon Energy to change its tariff calculation methodology for embedded generators. In all other respects, we approve Ergon Energy's large customer tariffs as we are satisfied these contribute to compliance with the distribution pricing principles.

Origin Energy made a submission is respect of embedded generators not having to pay distribution use of system charges. As this issue also applied to Energex, we have dealt with it under the Energex heading.

Ergon Energy's other large customer tariffs are not changing in structure over the 2017–20 period. These tariffs have been set on a cost reflective basis for some years. The only changes are for the tariff rates to adjust based on the building block revenue requirement set by our distribution determinations.

Over the coming tariff structure period, tariff rates will be declining relative to those for small and medium size businesses. This is because the latter will now be charged a price that is more representative of the costs they impose on the network through their usage decisions.

We approve the assignment of large business customers automatically to the most relevant tariff that reflects their circumstances. This represents no change to the way that Ergon Energy has approached these matters in the recent past, and ensures consistency in approach for existing and new customers.

We note that there were no additional comments from stakeholders in respect of large business customer tariffs.

We consider that the large customer tariffs which Ergon Energy has had in place for a number of years contribute to compliance with the distribution pricing principles. The tariffs prosed include time of use demand and capacity charging elements. These tariffs have been structured to recover the costs that each individual business imposes on the network.

Large businesses often have assets that are dedicated only to them. This makes it easier for the network to allocate costs to specific customers. Tariffs can then be set for specific customers. This is in contrast to the averaging of costs and therefore tariffs across a large number of customers, as occurs for small-medium businesses and the residential tariff class.

On this basis, we also approve large customers being mandated to demand tariffs, with no opt-out provision, from 1 July 2017. This ensures that those customers, who have sought an upgrade to their network assets which are dedicated solely or predominantly for their use, will bear the costs associated with the upgrade. In this way, they will face tariffs that reflect their contribution to the network costs of transporting electricity to their business premises. It also means they will not be cross subsidised by other electricity customers, who do not use those same assets.

Excess reactive power charge

We approve Ergon Energy's proposed excess reactive power charge (excess kVAr charge). We are satisfied that this is cost reflective and contributes to achievement of compliance with the distribution pricing principles because the network must be built to cater for reactive power demand. This charge sends an appropriate price signal to large customers who may invest in suitable equipment to avoid the reactive power charge.

Excess kVAr charges are applied when the actual kVAr exceeds the customer's permissible kVAr quantity. A customer's permissible kVAr quantity is determined by the customer's authorised demand and the Rules compliant power factor. In effect, at demands lower than authorised this allows lower than compliant power factors.

We are satisfied that the excess reactive power charge is an incentive for large customers to correct their power factor. This in turn reduces the apparent power required. Higher apparent power drives the need for network infrastructure. We note that these charges need not be are not aligned with overall the network system peaks.

In our draft decision we did not approve Ergon Energy's proposal to introduce the excessive reactive power charge to its Connection Asset Customers tariff class. We considered that further stakeholder consultation was required. In particular we received two confidential submissions to the original proposal highlighting an issue regarding embedded generators.

Ergon Energy has provided further information in its revised tariff structure statement. They have addressed the industry concerns of charging embedded generators for the short window where power is drawn from the network. Specifically Ergon Energy has stated that an embedded generator will not contribute to the load kVAr for any interval where there is generation.[87]

Embedded generators can draw significant power when starting. This temporary spike in demand may be above a customer's authorised demand. By negating the excess reactive power charge for this short window, this charge reflects the customer's power factor. However, this temporary spike in demand still requires the correct infrastructure to be built or maintained to supply it.

We would anticipate Ergon Energy to be monitoring the generators in its network. Owners of embedded generators can notify Ergon Energy and negotiate when they are

[87] Ergon Energy, *Supporting Information Revised Tariff Structure Statement 2017 to 2020*, 4 October 2016, p. 65.

about to start generation. Therefore all the embedded generators in a location can be staggered so they are not all drawing load at the same time. Using Network Agreements and a suitable notification procedure should reduce the need for allowing redundancy for start up reactive power.

Embedded generators are becoming more common. To that end, we consider that the application of the excess reactive power charge and embedded generators is reviewed in the future to ensure it remains appropriate.

7 Tariff levels

We approve Energex and Ergon Energy's approach to calculating long run marginal costs, passing those costs through to customers and dealing with residual costs.

We are satisfied these distributors' tariff structure statement proposals contribute to the achievement of compliance with the distribution pricing principles and other applicable requirements of the distribution pricing principles. The proposed tariff statements exhibit movement along the cost reflectivity spectrum, incorporating demand based tariff options for small customers and complementing existing cost reflective tariffs for large customers.

The distribution pricing principles state that each tariff must be based on the long run marginal cost of providing the services to which it relates to the retail customers assigned to that tariff.[88] A key concept that underpins the distribution pricing principles and the design of efficient network tariffs is the use of long run marginal costs. The Rules define long run marginal cost as the cost of an incremental change in demand over a period of time in which all factors of production can be varied.[89] This is also known as the forward looking cost.

Distributors take their allowed revenue requirement for a given year and recover this through both the long run marginal cost and residual cost elements of their tariffs.

7.1 Calculation and recovery of long run marginal cost

When tariffs accurately reflect the marginal or forward-looking cost of increasing demand, customers may make informed choices about their electricity usage. Tariff reform seeks to promote additional investment in the network by distributors only when customers value increased demand more than the cost of delivering the additional network capacity necessary to meet that demand.

We approve the Queensland distributors' approach to calculating long run marginal costs and passing those costs through to customers in the form of tariff structures.

We are satisfied these proposals contribute to the achievement of compliance with the distribution pricing principles.[90] This is because we are satisfied the proposals comply with the rule requirements for tariffs to be based on long run marginal costs and for the tariffs for each tariff class to be between stand alone and avoidable costs.[91] Our final decision is consistent with our draft decision on long run marginal costs.

Energex

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88 NER, cl. 6.18.5(f).

89 NER, Chapter 10–Glossary.

90 NER, cl. 6.18.5(f).

91 NER, cl. 6.18.5 (f)(1)(2)(3) and 6.18.5(e)(1)(2).

Energex used the average incremental cost method to calculate its LRMC. The inputs used include:[92]

- Its forward looking network augmentation costs (and related capitalised overheads),
- associated forecast operating costs,
- forecast demand over the same period,
- based on a 10 year forecast[93]

We approve the long run marginal costs being calculated via the average incremental costs approach. We do note that there are other methods available to calculate it but these are more complex to derive. For this first tariff structure statement period, we accept Energex's use of only including augmentation capex in its calculation methodology. However, we consider it should give consideration to including replacement capex in future estimates of long run marginal costs for the 2020-25 tariff structure statement period. This is because replacement capex is also a future cost, is marginal to the distributors cost base and can be affected by the value in use that customers place on the network.

In addition, as alternative non-network solutions might become more prevent over the coming years and decades, distributors ought to be taking into account whether substitute energy sources can provide some of the services currently provided only by the network grid. At the time of potential network upgrades or replacement, the distributor ought to consider whether replacing a transformer with one of a lower capacity is more economic than a mere like for like replacement. This could be because customers place a lower value on this additional investment than they do on the smaller replacement capex. All customers might still be provided with the same levels of reliability and security of supply via the application of distributed energy resources or other non-network alternatives. This will have benefits to customers through avoiding the need to pay for additional network capital investments.

For this 2017–19 tariff structure statement period, we approve Energex's use of the average incremental approach to long rum marginal cost calculation. We also approve the distributor's approach not to include replacement capex at this stage. However, as noted above, Energex should give consideration to this for future tariff structure statement periods.

Ergon Energy

To calculate its long run marginal costs, Ergon Energy adopted a similar average incremental cost method as Energex, but with some differences. Ergon Energy stated that its inputs to the long run marginal cost calculation include:

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[92] Energex, *Tariff Structure Statement, 1 July 2017 to 30 June 2020*, 4 October 2016, p. 8.

[93] AER Draft Decision, *Tariff structure statement proposal*, Energex and Ergon Energy, August 2016, p 56.

- Its forward looking network augmentation costs (and related capitalised overheads),
- connections costs
- a small (2.5 per cent) component of its forward looking asset replacement costs

Ergon Energy updated some of the inputs from the initial proposal for its calculations of average incremental costs.[94]

As set out in our draft decision, we support the inclusion of at least some replacement capital costs being included in the long run marginal cost calculation. We encouraged other distributors to consider this too.[95] While Ergon Energy has only included a relatively small component of repex in its revised proposal, the appropriate amount and approach should be considered in more detail in the lead up to their next tariff structure statement proposal for their next regulatory period.

'Long run marginal costs' is defined in the Rules to mean the cost of an incremental change in demand for direct control services provided by a distributor over a period of time in which all factors of production required to provide those direct control services can be varied. We consider there is no ideal, or correct, "period of time" over which to base these estimates. This is because the longer the estimation period is, the more difficult it becomes to estimate and forecast long run costs. Assumptions about future growth at zone substation and/or terminal stations also become more problematic with a longer planning horizon.

The Rules do not prescribe a particular method for estimating and calculating long run marginal costs. Historically, electricity distributors in the national electricity market have calculated their long run marginal cost using the average incremental cost approach. This methodology estimates long run marginal cost as the average change in forward looking operating and capital expenditure resulting from a change in demand. It is estimated by:

- Initially, estimating future operating and capital costs to satisfy expected increases in demand
- Then estimating the anticipated increase in the relevant charging parameter
- Finally, dividing the present value of future costs by the present value of the charging parameter over the time horizon chosen.[96]

Both Queensland distributors included augmentation costs plus operational costs associated with those upgrades to establish long run marginal cost estimates. Ergon

94 Energex, *Tariff Structure Statement, 1 July 2017 to 30 June 2020*, 4 October 2016, p. 42.

95 AER Draft Decision, *Tariff structure statement proposal*, Energex and Ergon Energy, August 2016, p 56.

96 Therefore, by definition, the calculation for long run marginal cost includes the time value of money. The present value of future costs is higher if the new investment is required imminently and lower if required later (given a positive rate of return).

Energy has also included a small component of replacement costs. Long run marginal costs were calculated by voltage level.

We consider that to derive long run marginal costs, it is important for the network to signal to customers the costs of future network investments that are required to ensure customers continue to receive a reliably supply of electricity. All customers subject to a particular tariff within a tariff class should face these signals. This is to ensure that all customers face the same incentive to use or not use the network at certain times, regardless of how much of the network they choose to use. This is the case even when a zone substation is yet to reach its capacity constraints.

With many of the Ergon Energy zone substations having a mix of business and residential customers, the distributor needs to ensure that its charging windows are set wide enough to capture the peaks that both these separate customer classes can impose on the network.

Current congestion

We are satisfied that current levels of congestion have been taken into account by Ergon Energy in calculating its long run marginal costs.

NERA's report for the AEMC refers to considering current capacity in calculating future capital expenditure for LRMC.

> Those locations where there is ample network capacity, changes in maximum demand will not influence forward looking costs whereas those locations where network capacity is constrained, changes in maximum demand will strongly influence forward looking costs.[97]

Further, in step 2 of designing network tariffs to promote efficiency, "Compare historic and forecast network demands with existing capacity".[98]

Canegrowers submit that we did not provide evidence in our draft decision that Ergon Energy had taken existing spare network capacity into account when calculating LRMC.[99] We approved in our draft decision the methods proposed by Ergon Energy to estimate its LRMC.[100] Frontier Economics, Ergon Energy's consultant, has stated the there is no need for investment to be required (to avoid congestion or otherwise) in the next three or four years.[101] This is somewhat consistent with Canegrowers' assessment of the 2016 DAPR – that a requirement for network augmentation is

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97 NERA – *Economic Concepts for Pricing Electricity Network Services: A report for the Australian Energy Market Commission* – 21 July 2014, p. 12.

98 NERA – *Economic Concepts for Pricing Electricity Network Services: A report for the Australian Energy Market Commission* – 21 July 2014, p. 22.

99 Canegrowers – Sapere – *Memorandum to AER* – 13 January 2017, p. 3.

100 AER Draft Decision, *Tariff structure statement proposals*: Energex & Ergon Energy – August 2016, p. 12.

101 Ergon Energy – Frontier Economics – *Response to Sapere claims on Ergon Energy's Tariff Structure Statement* – December 2016, p.17.

unlikely to be triggered until mid-2021.[102] Hence, we conclude that the LRMC calculation does take into account the current capacity of Ergon Energy's network.

Furthermore, Ergon Energy published calculations of the average incremental cost over a 25 year period with capital expenditure lagged by 3 years, as provided by its consultant, Harry Colebourn.[103]

Long run marginal cost

The Rules require network tariffs to be based on long run marginal cost (LRMC).[104] The AEMC's paper sets out its consideration of using short run or long run for calculating marginal costs.[105]

> While either short run marginal cost (SRMC) or LRMC can be used as a basis for providing efficient network price signals to customers, the Commission considers that LRMC represents the most appropriate measure. It is simpler to implement and provides more stable longer term price signals about the future network costs consumers can affect through their consumption decisions. Consumers are more likely to be able to better respond to more stable price signals.

NERA, in its report for the AEMC, state that: [106]

> SRMC provides strong short-term signals to manage near term capacity constraints.
>
> LRMC provides better signals for the signalling of long term infrastructure investment costs, and effectively replaces the congestion cost component embedded within SRMC, with the cost of infrastructure necessary to alleviate any congestion. This means that it provides strong signals to customers to make medium to long term investments to manage demand, while ensuring that infrastructure businesses receive signals for new capacity expansions.

We received multiple submissions on Ergon Energy's long run marginal costs, from Canegrowers and their consultant, Sapere Research Group (hereafter referred to as Canegrowers). Canegrowers contend that Ergon Energy's long run marginal cost calculation, and our draft decision to accept them, was based on incorrect information.

Canegrowers were of the view that because Ergon Energy has capacity constraints at only five of its zone substations, the long run marginal costs of its network would be relatively small.

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[102] Canegrowers – Sapere – *Memorandum to AER* – 13 January 2017, p. 1.

[103] Ergon Energy, *Tariff Structure Statement 2018-2020 Appendices* – November 2015, p. 28.

[104] NER, cl. 6.18.5(f).

[105] AEMC – *Rule Determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014* – 27 November 2014, p. 118.

[106] NERA – *Economic Concepts for Pricing Electricity Network Services: A report for the Australian Energy Market Commission* – 21 July 2014, p. 6.

In our view, long run marginal cost is associated with augmentation investment (that is future costs) and therefore forward price signals associated with these investments. We consider that Ergon Energy has complied with the Rules requirement to sets its tariffs on the basis of long run marginal costs. Canegrowers refer to marginal and infra-marginal network capacity throughout their submissions.[107]

> Under efficient tariffs, Canegrowers would certainly face peak network prices. But their exposure would be limited because their demand (MW) does not expand when total network demand approaches the secure capacity of the relevant part of the network. In this sense they can reasonably be described as using infra-marginal network capacity, rather than using marginal network capacity.[108]

> Marginal network capacity for price setting purposes may be defined as that part of network capacity where even small increases in future maximum demand can trigger a requirement for capacity augmentation to maintain firm supply. If this demand increase can be avoided, so can the requirement for augmentation.[109]

Canegrowers refer to the existing spare capacity within the network. Like other distributors, Ergon Energy has used the average incremental cost method to calculate long run marginal cost. This is a well-established methodology. Ergon Energy have taken account of existing spare capacity within their network by including in the calculation only the investment needed to augment the network.

There is no provision in the Rules for customers in the same class to be charged on a separate basis, other than when they are on different tariffs within that class. We consider it appropriate that all customers should face the same network price signals, as they all contribute to the peak demand and hence drive the capacity of the network in some way.

Therefore, all customers within a tariff class using the network during peak times should be subject to the peak tariffs of the applicable customer class. See further discussion in section 8.2. Canegrowers seems to be suggesting that irrigation customers are not the ones within the small and medium business customer grouping who are driving incremental investments on the Ergon Energy network, or likely to in the future. But this does seem to ignore that irrigation and other Canegrowers customers are often using the network during the times when it is more likely to be facing maximum demand. Ergon Energy's consultant's analysis also indicates that

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107 Canegrowers – Sapere – *Review of AER Draft Decision; Tariff Structure Statement Proposals, Energex and Ergon, August 2016* – October 2016. Canegrowers – Sapere – *Errors in AER's draft decision on Ergon Energy's 2016 Tariff Structure Statement* – 22 November 2016. Canegrowers – Sapere – *Memorandum to AER* – 13 January 2017.

108 Canegrowers – Sapere – *Errors in AER's draft decision on Ergon Energy's 2016 Tariff Structure Statement* – 22 November 2016, p. 13.

109 Canegrowers – Sapere – *Errors in AER's draft decision on Ergon Energy's 2016 Tariff Structure Statement* – 22 November 2016, p. 15.

during summer months, 10am to 8pm is the time when most peaks occur. Canegrowers seem concerned that this is a long period of time and represents a limited opportunity for irrigation and cane growers companies to adjust their levels of demand.

Ergon Energy in future tariff structure statements might be able to propose more disaggregated tariffs if it has the data, technology and information about its network to do so. It would need information about more localised costs and demands at given time periods to do so. However, this is for Ergon Energy to consider and propose. We are satisfied that Ergon Energy's current approach is consistent with achieving compliance with the distribution pricing principles.

LRMC as a percentage of total costs

Canegrowers also claim that LRMC represents 50 per cent of a typical residential bill is a substantial over-estimation of network congestion.[110]

We do not consider that just because a zone substation has spare capacity (i.e. demand is below the N-1 rating for the zone substation) that this implies that long run marginal costs will be close to zero.

Ergon Energy's consultant Frontier Economics states that a residential customer could save on their network bill by adopting a specific STOUD-based retail tariff. This was to demonstrate that residential customers could make considerable savings under a retail tariff incorporating the STOUD network tariff structure.[111] There was no further analysis provided of typical retail bills, as approved in our draft decision.[112] Therefore no further conclusions regarding LRMC should be inferred outside the reference to that specific retail tariff, especially as the retail tariffs are subject to the Queensland Government's Uniform Tariff Policy. Regardless, we do not have any evidence that it is unreasonable for LRMC to be 50 per cent of total network costs, or any other figure.

In addition, due to the additional responses from both consultants, there appears to be agreement that the 50 per cent figure was determined as a result of analysing the STOUD-based tariffs (and not used to reverse-engineer the tariff). Therefore, this aspect of the statement is not in dispute.[113]

7.2 Recovery of residual costs

We approve the recovery of Energex and Ergon Energy's residual (non-long run marginal costs) via the use of fixed supply charges and variable energy charges. We

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110 Canegrowers – Sapere – *Memorandum to AER* – 13 January 2017, p. 1. Sapere also make reference to 50% of a typical residential bill on pages 2, 4, 5 and 6.

111 Ergon Energy – Frontier Economics – *Response to Sapere claims on Ergon Energy's Tariff Structure Statement* – December 2016, p. 20.

112 AER Draft Decision, *Tariff structure statement proposals*: Energex & Ergon Energy – August 2016, p. 12.

113 Canegrowers – Sapere – *Memorandum to AER* – 13 January 2017, p. 5.

consider this approach contributes to the achievement of compliance with the distribution pricing principles and other applicable requirements in the Rules.

Both Ergon Energy and Energex have allocated their residual (or sunk) costs to be recovered through fixed supply charges and/or energy volume based (kWh) tariffs.

This is consistent with both distributors' approach in their initial tariff structure statements. We continue to approve this approach for the final decision, as we did in our draft decisions.

Distributors must recover their total costs.[114] The LRMC does not recover the costs that a distributor has already incurred to provide distribution services. The LRMC only recoups the forward looking costs. The distribution pricing principles require total costs be recovered in a way which minimises distortions to price signals for efficient usage resulting from tariffs reflecting long run marginal cost.[115] In this context, non–distortionary tends to mean unresponsive to customer usage. That is, because customers cannot avoid the residual costs they are asked to pay, they should respond to long run marginal cost price signals about their usage. For demand tariffs, to conform to the distribution pricing principles, distributors generally propose recovery of residual costs through a form of fixed charge.

Energex and Ergon Energy will use fixed supply charge ($ per month) and the variable charges (in kWh) to recover the residual costs from customers. These will be added to the long run marginal costs—in the kW demand charges— resulting in the final network tariffs that a customer pays.

All the jurisdictions we have looked at as part of the tariff structure statements are using fixed supply charges and variable usage charges to recover residual costs.[116]

We note also that retaining usage (kWh) charges in some form, rather than abolishing them altogether, may assist customers understanding of tariffs. Existing customers are familiar with usage charging components within tariffs. In this way, both Energex and Ergon Energy are minimising distortions to customer consumption behaviour. As the largest portion of a distributors costs are largely fixed (that is, these investments have been made in the past and need to be recovered from users), it is efficient to charge customers a fixed supply charge within a tariff. This has been a long standing approach to distribution network charging over many decades.

Given this, we approve Energex and Ergon Energy's approach to use a fixed supply charge and the variable charge to recover the residual costs from customers as contributing to the achievement of compliance with the distribution pricing principles.

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114 NER, cl. 6.18.5(g).

115 NER, cl. 6.18.5(g).

116 The once exception is TasNetworks, which is using the fixed supply charge only to recoup residual costs. There is no variable kWh energy charge for residential customers.

7.3 Future direction

We encourage distributors to continue to refine their methods for estimating long run marginal cost. We consider it is possible for distributors to make further refinements while retaining the average incremental cost method in future tariff structure statements. Alternatively, we would also be open to distributors adopting more sophisticated estimation methods, such as the Turvey method.

We also consider distributors should have the flexibility to calculate and apply long run marginal cost in the way that best suits the characteristics of their networks and customers.[117]

All electricity distributors currently calculate their long run marginal cost using the average incremental cost approach. This approach estimates long run marginal cost as the average change in forward looking capital and operating expenditure resulting from an increase in demand. It is estimated by:

- Initially, estimating future operating and capital costs to satisfy expected increases in demand
- Then estimating the anticipated increase in the relevant charging parameter
- Finally, dividing the present value of future costs by the present value of the charging parameter over the time horizon chosen.

The Energy Networks Association submitted the average incremental cost approach is incapable of estimating how the long run marginal cost might change where consumption or demand is falling in parts of the network.

This appears to stem from the standard specification of the average incremental cost function. It involves taking the ratio of future expenditure required to serve demand (in present value terms) to the additional demand served (also in present value terms). If there is decreasing demand, the average incremental cost approach has an undefined denominator. Hence, it cannot produce estimates of long run marginal cost.

We suggest distributors explore adapting the average incremental cost approach for situations where demand is decreasing, for example, by using a slightly different concept for the numerator. They can specify the numerator as the avoidable cost due to a demand decrement. This is analogous to the way more advanced methods, such as the Turvey method, are able to estimate long run marginal cost under falling demand conditions. Alternatively, distributors may consider adopting more advanced methods, if they consider it is appropriate to do so.[118]

In addition to refining the specification of the method for estimating long run marginal cost, we encourage distributors to continue refining the way they apply these methods. We expect distributors to utilise inputs that better represent long run marginal cost. In

[117] NER, cl. 6.18.5(g).

[118] For example, the Turvey method.

particular we consider long run marginal cost estimates should incorporate certain types of replacement capital expenditure, and associated operating expenditure, in addition to augmentation expenditure (and associated operating expenditure).

The definition of long run marginal costs in the Rules is the cost of an incremental change in demand over a period of time in which all factors of production can be varied.[119]

In the long run, the level of capacity in a distribution network is a factor of production that can be varied. 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. To promote network capacity in the long run being at a level consumers value, we consider replacement capital expenditure (and associated operating expenditure) should be included within long run marginal cost estimates.

This differs from the approach that most distributors have reflected in their proposals for this first round of tariff structure statements, which have typically excluded replacement capex from long run marginal cost estimates. Distributors generally base their LRMC estimates on augmentation capex alone on the basis that this is the only ‘growth’ capex. However, this reasoning overlooks that the level of network capacity (whether to increase, maintain or decrease) is not fixed in the long run.

We encourage the distributors to review this element of their long run marginal cost methodology in the lead-up to the next round of tariff structure statements.

[119] NER, Chapter 10—Glossary.

8 Charging windows

This chapter sets out our views in respect of the charging windows adopted by the Queensland distributors to signal the impacts of peak demand on their networks.

Selection of peak charging windows is an important element of pricing. The correct window will allow customers to understand the period to time when their demands are most likely to place constraints on the network, potentially requiring future augmentations.

The windows also need to be at a level that customers can respond. This is one of the pricing principles.[120] Windows need to be wide enough to capture the beginning and end of the peaks, but not so wide that customers cannot respond and mitigate the impact of the peak window. If a window is too short it may result in customers shifting their usage slightly and creating a new peak just outside the window.

8.1 Residential charging windows

Energex

We approve Energex's residential peak charging windows as we are satisfied they contribute to the achievement of compliance with the distribution pricing principles.

Energex set its residential peak window at 4pm–8pm on weekdays only, throughout the year.[121]

Based on information in Figure 8-1, it can be seen that the level of demand is starting to increase from just after 12 noon during summer, winter and the remaining months of the year.

Energex has proposed not to differentiate between the months of the year when applying the demand charge. Instead, it has proposed to apply this charge all year round. However, it proposes to apply less expensive demand rates during the non-summer period compared to summer months. By proposing a demand charge that applies year round, Energex is also attempting to ensure consistent tariff messaging for retailers and customer generally.

Additionally, by proposing year round demand tariffs, Energex is likely able to reduce the length of the peak charging window from that which might otherwise apply.

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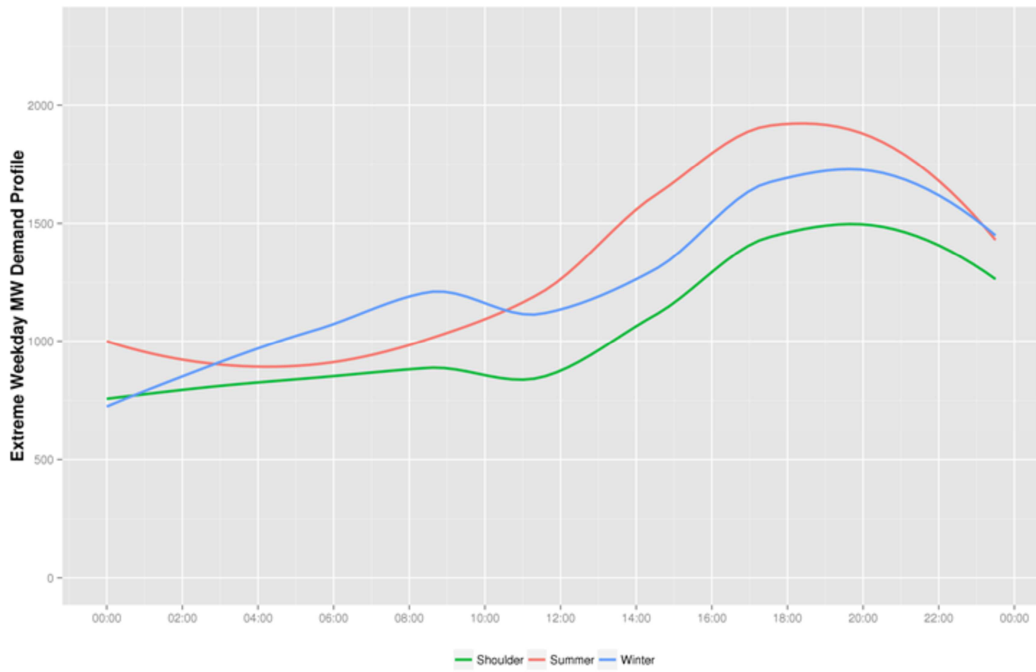
120 NER cl. 6.18.5(h)(3).

121 Energex, *Tariff Structure Statement, 1 July 2017 to 30 June 2020*, 4 October 2016, p. 28. The residential peak window is defined as workdays, which is weekdays excluding government-specified public holidays.

Figure 8-1 Energex half hour demand profile, maximum MW



Source: Energex

A further important element for Energex proposing this peak period is that it also has a load control scheme that cycles hot water units and other controlled loads after 8pm. These are used to mitigate any residential demand that may occur after that time. Consequently, Energex considers that it can manage the still relatively high but falling demand that occurs after 8pm.

We consider these combined approaches contribute to achievement of compliance with the distribution pricing principles. They take into account customer impacts and enable customers to respond to the tariff by having some of their appliances attract an off-peak price. Furthermore, these types of controlled load tariffs are familiar with Queensland customers, having been used by Energex to date. Thus, they ease customers' transition towards more cost reflective tariffs, by taking into account customer impacts and existing arrangements.[122]

Ergon Energy

We approve Ergon Energy's residential peak charging windows as we are satisfied they contribute to compliance with the distributions pricing principles.

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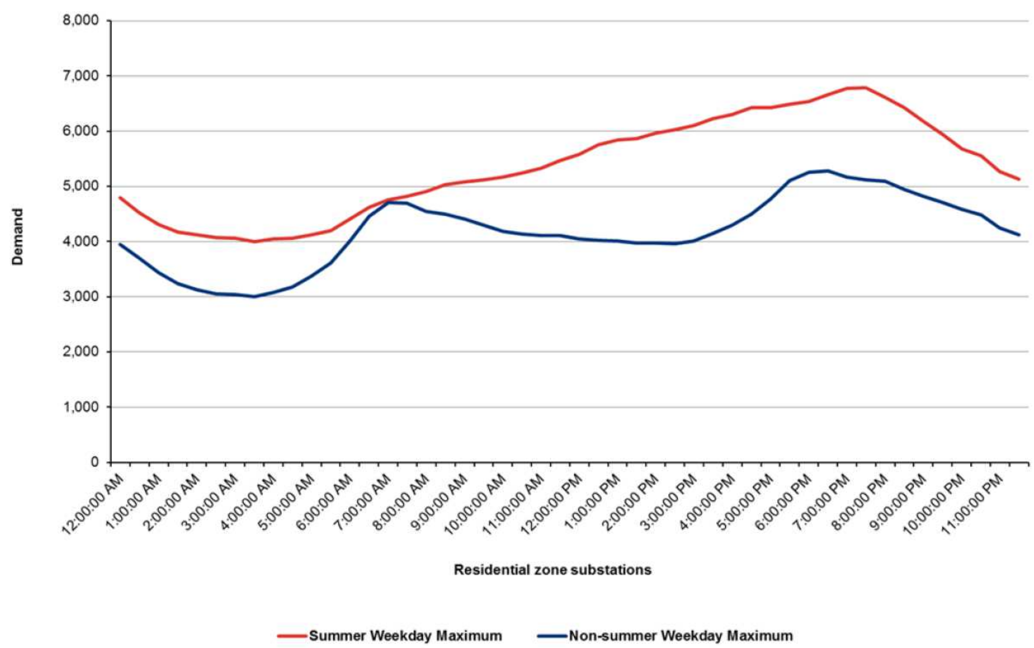
[122] NER, cl. 6.18.5(g) and cl. 6.18.5(i).

Taking into account load profile across zone substation, Ergon Energy set its peak charge window for residential customers at 3pm to 9.30pm summer days. We accepted the peak charging windows in our draft decision.

In Figure 8-2 we can see the increase in demand during the summer months on Ergon Energy's network using the load profile. We note that load profiles have been used by other distributors to establish their peak and off peak charging windows.

Canegrowers also commented that residential and business customers should have charging windows of the same length of time. It is important to remember that Ergon Energy's peak charging window for business customers (10am to 8pm weekdays) only applies during summer months. This means it applies for around seven per cent of the year. In this respect the charging window is not particularly long. It is during summer months when the Ergon Energy network is most likely to have its maximum demand.

Figure 8-2 Ergon Energy half hour demand profile, maximum MW



Source: Ergon Energy and Energeia for East Zone

In analysis undertaken for Ergon Energy by its consultant Energeia, they show that for a sample of agricultural customers in the standard asset class-large customer tariff class, this has the peak usage mostly occurring around noon to approximately 6pm. This is not too dissimilar to the 10am to 8pm. Energeia considered that the results may be similar for the standard asset class – small business customer class and therefore the charging window as proposed was appropriate.[123] Distributors usually set the beginning and end of their peak charging windows to be longer that the peak shown by actual data. This is to ensure that they fully capture any movements in the peak that may occur at the margin.

We consider that Ergon Energy's use of load profile data is an appropriate method for establishing charging windows. It is similar to that used by other jurisdictional distributors. The information presented by Ergon Energy on its demand profiles also indicates the time period when residential demand is most likely to occur.

We also consider it is relevant that a peak period extend sufficiently beyond the time when the maximum peak is reached. This is to ensure that customers do not merely shift their peak usage from one time period to another. This can happen if the peak period is set too short.

For these reasons, and based on the evidence presented by Ergon Energy, we approve the residential peak charging window. We have considered the submissions from Canegrowers which apply to the charging windows for both residential and business customers. We have responded to them in Ergon Energy's business charging windows in Chapter 8.2.

8.2 Business charging widows

Energex

We approve Energex's business charging windows as we are satisfied they contribute to the achievement of compliance with the distribution pricing principles.

We consider they take account of likely period of demand on the Energex network, take into account the nature of the business customers connected to the network.

Customers in the individual calculated customer tariff class do not face peak charging windows. This is because these very large customers have discrete loads that can occur at any time and are of a large magnitude. Thus, they can create a network peak during any time period.

Energex's level demand from 9am to 9pm is targeted. Energex intends to use the this peak charging window to encourage business customers to reduce their peak demand with in the period, rather than necessarily get them to shift operations to off-peak times per se.

In our draft decision, we approved Energex's peak charging windows for business customers. Nevertheless, we encouraged Energex to review the length of the charging window in light of stakeholder comments on this topic.

[123] Energeia, letter to Ergon Energy, *Re: Application of the National Electricity Pricing Rules to Ergon's STOUE and STOUD tariffs*, 9 December 2016, p.3.

Trade Coast Central was concerned by the overly long peak, and thought a peak beginning around midday and finishing at around 8pm was better. We discussed these issues with Trade Coast Central, and jointly with Energex.

Energex advised that there is a mix of business and residential customers on most of its zone sub stations. It wanted to stagger the peaks for these (Residential 4pm to 8pm, business 9am to 9pm) to ensure there was no overlap that could lead to additional peaks at an earlier or later time. Table 8-3 shows the large customer charging windows.

Table 8-3 Energex large customer tariff charging windows

Tariff	Charging window 1	Charging window 2	Charging window 3
LV large demand	No charging window - demand charge based on highest demand in billing period		
LV demand time of use	9am to 9pm		
Demand time of use 11kV	Peak demand charge 9am to 9pm weekdays	Excess demand charge 9pm to 9am weekdays	

Large customers are more likely than small customers to have network assets dedicated to their use only, or predominantly for their use. This gives weight to basing time varying charges on the highest demand recorded at any time rather than at times aligned to broader network peak demand. Nonetheless, large customer demand may also contribute materially to broader network demand.

We still consider that Energex's peak charging window reflects its costs and the demands that are put on the network. Energex needs to be able to recover its costs from our distribution determination and minimise distortions to price signals.[124] Setting a charging window that is too short could incentivise customers to use the network at the wrong time (i.e. when the network might be peaking). This might ultimately lead to further network augmentation to meet the higher demand, rather than less.

We consider that these charging windows meet the distribution pricing principles and will help customers to see the impacts of their decisions to use the network at peak times. We do note the impact that a mix of business customers and residential customers within Energex's zone substations can have on the ability of the network to control peak demand. The staggering of the times for peak period application between business and residential customers (9am to 9pm for the former, 4pm to 8pm for the latter) helps to mitigate the risk that the peak demands for both types of customer occur at the same time.

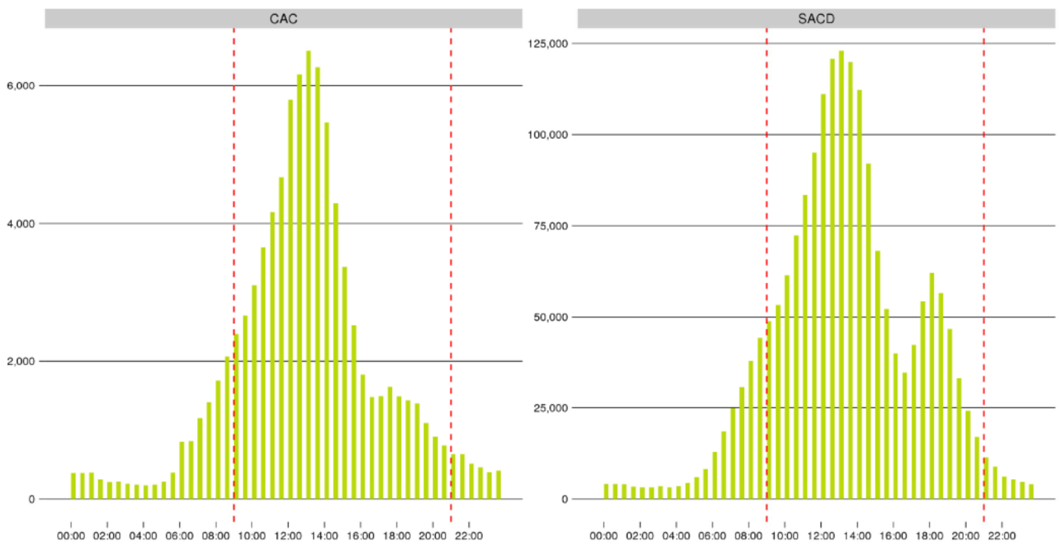
Our draft decision requested Energex have a look at the peak period times for business customers, given that some stakeholders had queried the length of the

[124] NER, cl. 6.18.5(g).

business peak charging window.[125] Energex undertook analysis to see if the peak period window could be wound back an hour, to conclude at 8pm for business customers.

In its revised proposal, Energex provided supplementary information to explain the rational for its 9am to 9pm business peak. In Figure 8-4 Energex shows the top one percent of maximum demand for business customers in the twelve months to August 2016. It does reveal that peak demand across these two business tariff classes are beginning to rise sharply from early morning. It shows that mostly for the smaller to medium sized business in the standard asset customer class, the number of customers experiencing peak demands does not drop away quickly until approximately 7.30pm onwards.

Figure 8-4 distribution of Energex top one per cent of monthly demand for CAC and SAC demand customers



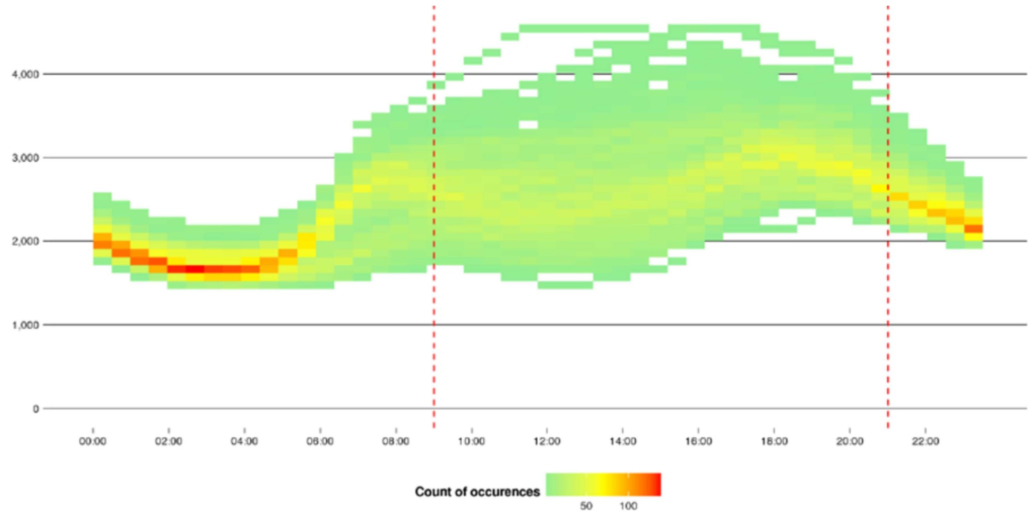
Source: Energex

In Figure 8-5 we observe from Energex that their maximum demand for both business and residential customers over the year to June 2016. Demand stays high (represented by the green shading) and begins to dip from approximately 7.30pm or just after. Energex states this is due to the occurrence of both residential and business customers being served by the majority of zone substations.[126] It is this coincidence of peak demands that has resulted in Energex extending the peak until 9pm for business customers rather than ending the peak charge at 8pm.

[125] Trade Coast Central, *Submission on AER Issues paper re QLD electricity distributors proposed tariff structure statements*, 28 April 2016, p 3, Trade Coast Central, *submission to AER on draft decision Qld DNSPs Tariff Structure Statement 2017-20*, 4 October 2016, p. 2 and separate discussions with AER staff.

[126] Energex, *Tariff Structure Statement Explanatory Notes, 1 July 2017 to 30 June 2020*, 4 October 2016, p. 51.

Figure 8-5 Energex total MVA demand for zone substations, 2015–16



Source: Energex

Trade Coast Central's submission did agree that Energex's revised tariff structure statement did provide additional useful information about time of likely peak demand.[127] Trade Coast Central considered there was now sufficient justification in the above figures to support a 9am to 9pm charging window.[128]

Based on the information now provided, we accept Energex's view that if the peak business charging window finishes earlier than 9pm there is a risk of a new peak being created from around 8pm. This is due to zone substations serving a mix of both residential and business tariff class customers. A slight staggering of the peak windows reduces (but does not eliminate) the chance of this occurring.

Nonetheless, Energex is encouraged to continue monitoring the effects of the 9am to 9pm peak charge windows on its business customers. There may be opportunities in future tariff structure statements to amend the charging window to accommodate changes in businesses' consumption and demand patterns. Additional information can always be used to inform improvements in future tariff charging windows. This will ultimately ensure that the peak periods chosen most represent the peak demand profile of customers and the network as a whole.

Ergon Energy

We approve Ergon Energy's peak charging windows for business customers. We are satisfied that they contribute to achievement of compliance with the distribution pricing principles.

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[127] Trade Coast Central, *Re: Energex's revised Tariff Structure Statement proposal*, 25 October 2016, p.1.

[128] Trade Coast Central, *Re: Energex's revised Tariff Structure Statement proposal*, 25 October 2016, p.1.

For the STOUE and STOUD tariffs, Ergon Energy proposed a charging window of 10am to 8pm. This was based on an analysis of load profiles at zone substation level.

We consider that the 10am to 8pm peak charging window for customer on the STOUE and STOUD tariffs are an appropriate balance between improved cost reflectivity and simplicity and are capable of being understood by customers.[129] However, we note that the peak charge window is only to apply during summer months, and only for weekdays. Ergon Energy's peak charge window for business customers applies for 650 hours of the year, which makes it relatively short compared to other distributors in the NEM.

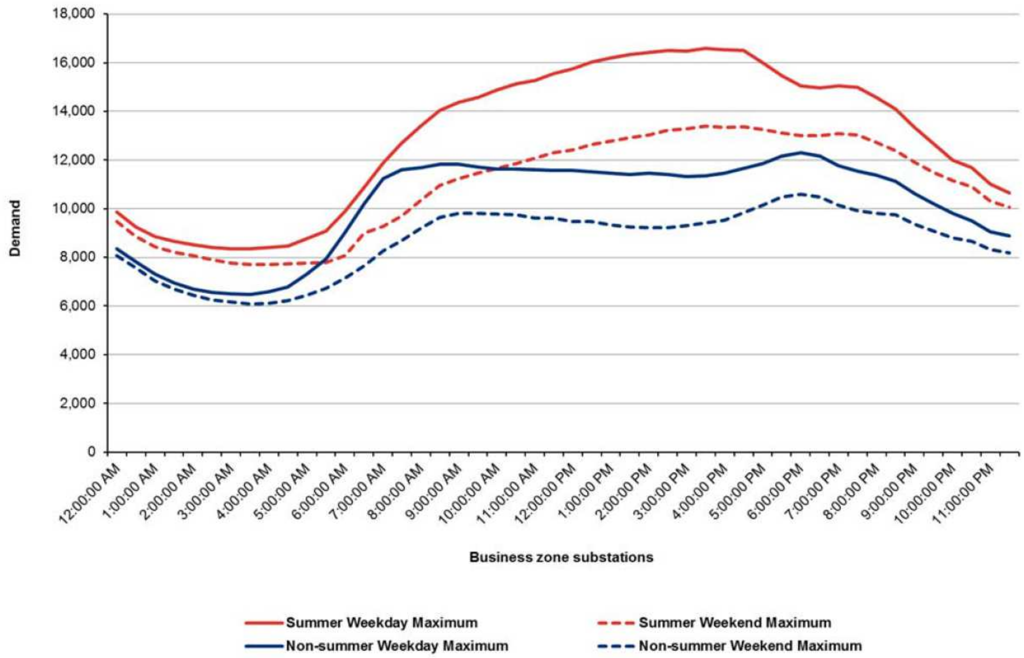
We consider that Ergon Energy's use of load profile data is an appropriate method for establishing charging windows. It is similar to that used by other jurisdictional distributors. The information presented by Ergon Energy on its demand profiles also indicates the time period when residential demand is most likely to occur.

We also consider it is relevant that a peak period extend sufficiently beyond the time when the maximum peak is reached. This is to ensure that customers do not merely shift their peak usage from one time period to another. This can happen if the peak period is set too short.

We approve the approach for setting the business charging windows for this tariff structure statement.

[129] NER, cl. 6.18.5(i).

Figure 8-6 Ergon Energy half hour demand profile, maximum MW



Source: Ergon Energy and Energeia for East Zone

In the draft decision we considered that Ergon Energy's peak period concluding at 8pm took into account this effect. The load profile in Figure 8-6 shows this. If a much shorter peak period was used some business customers may move their demand to either side of this shorter peak. This would result in creating a new network peak at a new time of day, rather than the peak being reduced. This outcome would result in little network investment deferral, and thus no long term benefit to customers via lower overall tariffs, or the network business, whose costs to supply would remain high. This would eventually lead to the increased investment to maintain reliable and safe supply to customers.

We received submissions from Canegrowers that questioned the length of these charging windows and the method for their calculation, both for residential and business customers. Notably, Canegrowers suggested that the charging window should be much shorter than Ergon Energy's proposal. They submitted that a smaller window, of around five hour's duration, was more appropriate. Ergon Energy used a load profile to establish the charging windows. Canegrowers submitted that a load duration curve ought to have been used instead.[130] Canegrowers did not consider that this peak charging window was sound.

Load duration curves

Canegrowers considers a load duration curve ought to have been used by Ergon Energy to calculate the number of hours that a peak demand charge should be applied. There are no definitive reasons for why one measure is superior to the other. We note that other distributors have used load profile data to estimate either peak windows. Others have used load duration curves.

The load duration curve can show the peakiness of a load and is therefore informative. But it is our understanding that a load duration curve is not as useful for attempting to understand what time of the day the peak occurs whereas the load profile can provide this information. Load profiles show what the load looks like over the peak day, or indeed any day or average of days. The load profile can also be applied over a week or month, not merely a day. Either way, this at least helps with an indication of what time of day a peak period should start and end. Nevertheless, by averaging loads in a load profile, this can also obscure the peakiness of a load, and therefore could also give rise to a bias either for or against a given charging window's length.

Ergon Energy's use of the load profile data to ascertain the peak charging window is also considered by us to be reasonable. See the discussion in section 8.1 above. Canegrowers submit that a load duration curve would represent a better measure, and that by doing so, it would be observed that fewer hours should be applied to the peak charging window.

We consider that load duration curves may be appropriate in conjunction with load profile data to determine peak charging windows. However we consider the use of a load profile is justified to set a charging window. We also consider it is relevant that a peak period extends sufficiently beyond the time when the maximum peak is reached. This is to ensure that customers do not merely shift their peak usage from one time period to another. This can happen if the peak period is set too short. For these reasons, and based on the evidence presented by Ergon Energy, we approve the residential and business peak charging windows proposed by Ergon Energy.

It is also important to consider that a distributor must set its charging window in the expectation that customers may alter their load to avoid peak prices. Thus, the window needs to be long enough to capture this instance, to avoid merely shifting the peak by an hour or so. For this reason, peak charge windows often finish sometime after the zone substation or network wide peak has passed. This has been the basis for a number of distributors throughout the national electricity market setting a charging window that begins before and finishes past the period when the peaks most commonly occur.

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130 Canegrowers – Sapere – *Errors in AER's draft decision on Ergon Energy's 2016 Tariff Structure Statement* – 22 November 2016, p. v.

This provides some opportunity for customers within the standard asset class- small business and standard asset class-large, to shift their operations to take account of off-peak rates. Any customer who is using the network during times when peaks are likely to occur should face an appropriate price signals about the costs of that usage.

Peak demand and network congestion

The Canegrowers considered that customers should not be charged a peak price when actual demand is unlikely to cause network congestion.[131] Their report was submitted to us following a meeting between AER, Canegrowers and Ergon Energy representatives on 2 November 2016.

Our role is to assess if a distributor's proposed tariffs and charging windows comply with the distribution pricing principles in the Rules. Our role does not extend to deciding if one form of tariff is better than another and so should be substituted for the proposed tariff.

There is no requirement in the Rules for congestion based pricing per se, t. Ergon Energy's proposal needs to comply with the requirement to set tariffs on the basis of long run marginal cost.[132] We have therefore focussed our review on whether Ergon Energy's proposal complies with this requirement, not whether short run marginal cost is superior to long run marginal cost for setting tariffs, or if some other form of cost reflective pricing is better than another. We have further discussion on marginal costs in Chapter 7.1.

In addition, there is no location based pricing with Australia's distribution networks. Ergon Energy does have prices reflect whether customers are in its east, west or Mt Isa zones, however beyond that there is no specific zone substation specific pricing. It is this level of granularity that Canegrowers submission seeks to emphasise and considers should be implemented.

Canegrowers submission does make reference to very few Ergon Energy zone substations facing congestion at present or in the near future. On this basis, they claim that demand would be suppressed by having a wide peak charging window and thus high tariffs when congestion is actually low (that is, the capacity of the zone substation well exceeds the demand at that zone substation). Canegrowers suggests that firm capacity should be used instead of peak demand to set the charging window.

Canegrowers suggested that peak charging windows, if established by load duration curves, should be established by reference to congestion occurring on peak days, not by the average of consumption over a number of days within the summer billing period.

We do agree with Canegrowers that this is a method by which a distributor could attempt to calculate the impact of demand or congestion on its network and set

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131 Canegrowers – Sapere – *Errors in AER's draft decision on Ergon Energy's 2016 Tariff Structure Statement* – 22 November 2016, p. 19.

132 NER, cl. 6.18.5(f).

charging windows accordingly. There can be more than one method to establish this. Our role is to assess if a distributor's proposal complies with the distribution pricing principles, not if a better approach exists.

Customers driving the peaks

Network tariffs in the NEM are not set on the basis of each individual customer's actual contribution to demand. Rather, tariffs are averaged across a customer class, and all customers with a class bear a share of costs incurred to supply that class of customer. This is so even if some of those customers did not have air-conditioning or other high use energy appliances and so contributed less than their share to demand growth. This charging basis applies at the low voltage residential and business customer class, to which most irrigators and cane growers are assigned.

Canegrowers have submitted that irrigators are capable of responding to well designed price signals targeted at periods of greatest utilisation of the network.[133] Canegrowers also suggested that irrigation and cane growers had not contributed to peak demands in recent years and that air conditioning was the main driver of demand. On this basis, they recommended these customers should not face peak demand prices or the peak charge windows.

Ergon Energy considered that cane growers and irrigators would be capable of responding to the price signals through their business operations. Canegrowers did not consider this would be the case. Ergon Energy's own understanding is that irrigation load is heterogeneous and subject to a greater range of variations than most load. The variations are being driven by irrigation technology and operating regimes, weather, location, water availability, price of the growers input and industry. Even the same customer can present very differently on a year on year basis.[134] With appropriate metering becoming more prevalent, both customers and retailers will be able to understand usage patterns better. Ergon Energy, in partnership with Ergon Energy Retail, is conducting a real life tariff trial, to enable customers to gain experience and understanding of the new cost reflective tariffs.[135] We consider that the information from this tariff trial may assist to further refine the business charging windows in future tariff structure statement periods. The outcomes of the tariff trial might also show if or how irrigators respond to the time varying and demand tariff structures. But this does need to be tempered by acknowledging that these customers will still see the lower Energex tariff rates applied to these tariff structures. This will likely mute customers' response.

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[133] Canegrowers – Sapere – *Review of AER draft decision; Tariff Structure Statement Proposals, Energex and Ergon* – October 2016, p. v.

[134] Ergon Energy, *Revised Tariff Structure Statement 2017-2020 Supporting Information* – October 2016, p. 71.

[135] Ergon Energy, *Revised Tariff Structure Statement 2017-2020 Supporting Information* – October 2016, p. 10.

We held workshops with Ergon Energy and Canegrowers to understand the issues and received submissions from both parties.[136] Both parties provided further submissions. These have been addressed in the appropriate sections. In particular charging windows is discussed above and tariff levels in Chapter 7.

Nevertheless, this disregards that any customer within a tariff class should face a signal about use of the network during its likely times of peak demand.

It does not necessarily matter which customer within a tariff class is causing the network to reach its maximum demand limits, only that any customer who utilises the same assets could potentially drive demand growth. On this basis, all such customers should face the same peak price signal. Only at high voltage levels are customers given a site specific network tariff, reflecting that these customers do have network assets dedicated only to them.

We find that using maximum demand is a reasonable basis for setting charging windows. It has been applied by distributors in other jurisdictions. It signals the extent to which a network may be affected by load at a particular zone substation (location) or across the network as a whole. Without location specific pricing, it is difficult to implement Canegrowers suggestion of only targeting certain zone substations for peak charge pricing. However, this may be possible in future years and Canegrowers recommendations might then be considered by electricity distributors as more probable of being introduced.

The method proposed by Canegrowers could apply if there was specific location based pricing, that did target very specific localised congestion (demand exceeding network ratings) or peak demand (where maximum demand can still be below the rated capacity of a zone substation). However, as noted above, this localised pricing is not yet part of the network charging arrangements. Further, we consider that Ergon Energy's approach of using load profile data of individuals is a reasonable method for measuring demand and charging windows and so contributes to compliance with the distribution pricing principles.

We approve the charging window prosed by Ergon Energy as we are satisfied they contribute to the achievement of compliance with the distribution pricing principles.

Ergon Energy – large business customers

For its largest customer tariffs, Ergon Energy has sets a peak charging windows—See Table 8-7—only for its seasonal time of use demand tariffs within the standard asset customer and connected asset customer classes. Otherwise, demand is simply charged as the highest demand in a billing period. Some of these tariffs were

136 A workshop was held on 2 November 2016 at the AER's offices in Melbourne and Brisbane. Submission are available on the AER website.

introduced over time as customers sought more transparency and simplicity in the tariff design.[137]

We approved theses charging window in our draft decision as contributing to compliance with the distribution pricing principles. For this final decision, we also approve these same tariff structures as set out in Ergon Energy's revised tariff structure.

Table 8-7 Ergon Energy large customer tariff charging windows

Tariff	Charging window 1	Charging window 2	Charging window 3
SAC large demand	No charging window – demand charge based on highest demand in billing period		
SAC seasonal time of use demand tariffs	Peak demand charge 10am to 8pm summer weekdays		
CAC standardised tariffs	No charging window – demand charge based on highest demand in billing period		
CAC seasonal time of use demand tariffs	Peak demand charge 10am to 8pm summer weekdays		

8.3 Future direction

We encourage distributors to continue making refinements to their charging windows in future tariff structure statements to more closely reflect the times of congestion on their particular network. Broadly, we encourage distributors to refine:[138]

- their methods for setting charging windows, and
- the charging windows themselves

We discuss these in turn below.

Methods for determining charging windows

Distributors used varying methods and information to support their proposed charging windows in this first round of tariff structure statements. We therefore assessed each distributor's proposed charging windows on the basis of their individual method. We assessed whether their methods and the information they provided in their tariff structure statements were sufficiently robust (given this early stage of tariff reform).[139] We then assessed whether the resulting charging windows were consistent with the findings of their methods and reasonably signalled the potential timing of congestion on

[137] Ergon Energy, *Revised Tariff Structure Statement 2017 to 2020*, 4 October 2016, p.32.

[138] NER, cl. 6.18.5(a).

[139] NER, cl 6.18.5(a) and (h).

their networks. We regularly consulted with the distributors to better understand the justification for their proposed charging windows. We did this through information requests to the distributors, for example, to get the dataset and models underlying their analysis, or to get their datasets in different formats. We also had discussions and workshops with the individual distributors to clarify issues identified during our assessment.

We consider the methods and information from each distributor provided sufficient support for their proposed charging windows for this first round of tariff structure statements.[140] However, we consider distributors should continue to explore ways to refine their methods for determining charging windows in future tariff structure statements.

All of the distributors provided some form of daily load profiles to determine or provide justification for their proposed charging windows in this first round of tariff structure statements.[141] For example, Essential Energy provided the 'average weekday' and 'average weekend' load profiles for summer and winter. Several distributors provided the actual load profile for the peak day of the year.[142] ActewAGL provided a load profile that showed the maximum demand measured for each half-hour interval for a given year.[143] Ausgrid and Endeavour Energy showed the time of the highest demand points for a given year (using data from several years).[144] Distributors variously provided daily load profiles at system and/or spatial levels.[145]

Each distributor also provided other types of information to supplement daily load profiles and further support their proposed charging windows, including:

- graphs showing the frequency of peak times for each half hour interval[146]
- 'heat maps' of demand[147]
- timing of peak demand for individual substations[148]
- load duration curves (see the 'network utilisation information' section below for further discussion).[149]

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[140] For our detailed assessment of the distributors' charging windows and methods, see our final decisions for the revised tariff structure statements of distributors in NSW, ACT, South Australia and Queensland.

[141] Daily load profiles depict the level of demand for each half-hour interval over 24 hours.

[142] See the revised tariff structure statements of Essential Energy, SA Power Networks, ActewAGL, Ergon Energy and Energex.

[143] ActewAGL, *Revised tariff structure statement: Explanatory statement*, 4 October 2016, p. 78.

[144] This is a 'semi-complete' load profile as it does not include data points for all half-hour intervals of the day.

[145] Spatial level means the daily load profiles applies to particular assets in the networks, particularly zone substations. System level means the daily load profiles applies to the distributor's network as a whole.

[146] For example, see Essential Energy, *Tariff structure statement: Attachment 8: Addendum to our tariff structure statement: Explanations and reasoning*, 4 October 2016, p. 14.

[147] See Energex, *Tariff structure statement: Explanatory statement*, 4 October 2016, p. 45.

[148] See Ausgrid, *Revised tariff structure statement*, 4 October 2016, pp. 32 and 35; Essential Energy, *Tariff structure statement: Attachment 8: Addendum to our tariff structure statement: Explanations and reasoning*, 4 October 2016, p. 15.

The distributors provided the information described above in formats showing demand levels only. Such information did not explicitly consider network capacity or utilisation (Endeavour Energy's approach to using load duration curves indirectly considers network utilisation as we discuss in the next section).

We consider focusing on demand levels only may be reasonable in the first round of tariff structure statements. Tariffs historically applied at the network (rather than regional or local) level and so send averaged signals of the drivers of network costs.[150] The first round of tariff structure statements largely maintained the use of tariffs that apply network-wide, which we consider is consistent with the customer impact principle.[151] The shape of daily load profiles supplemented by other demand-based information as described above can suggest when the network may be experiencing congestion. We consider such information serves to indicate the potential timing of network congestion under tariffs that apply network-wide. Hence, we consider such evidence contributed to the achievement of compliance with the distribution pricing principles in this first round of tariff structure statements.[152]

However, we expect the distributors to transition towards more cost reflective tariff structures in future tariff structure statements, including potentially moving away from network wide tariff approaches. Among other things, this could include charging windows that more accurately reflect times of network congestion than currently. From our assessment of the first round of tariff structure statements, we make several suggestions for distributors to explore to facilitate this transition. We discuss these in turn below.

Network utilisation information

The evidence the distributors provided generally showed information regarding demand levels only. As we noted earlier, we consider this is reasonable in this first round of tariff structure statements. However, it is network utilisation—the relationship between demand levels and asset capacity—that is a key driver input into distributors' decisions to make investments in the long run. Distributors' long run investment decisions are guided by their expectations of network utilisation. For example, they would invest in additional capacity when they expect demand to exceed the capacity of assets.[153] We therefore encourage distributors to explore whether they can incorporate information on network utilisation to develop and evidence their charging windows in future tariff structure statements.

We consider Endeavour Energy's revised proposal provided a useful starting point for exploring such an approach. Endeavour Energy justified its peak and shoulder hours

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149 See Endeavour Energy, *Tariff structure statement: Explanatory statement*, 4 October 2016, pp. 46–47.

150 With the exception of customer-specific tariffs, which apply to very large customers.

151 NER, cl 6.18.5(h) and (i).

152 NER, cl 6.18.5(a).

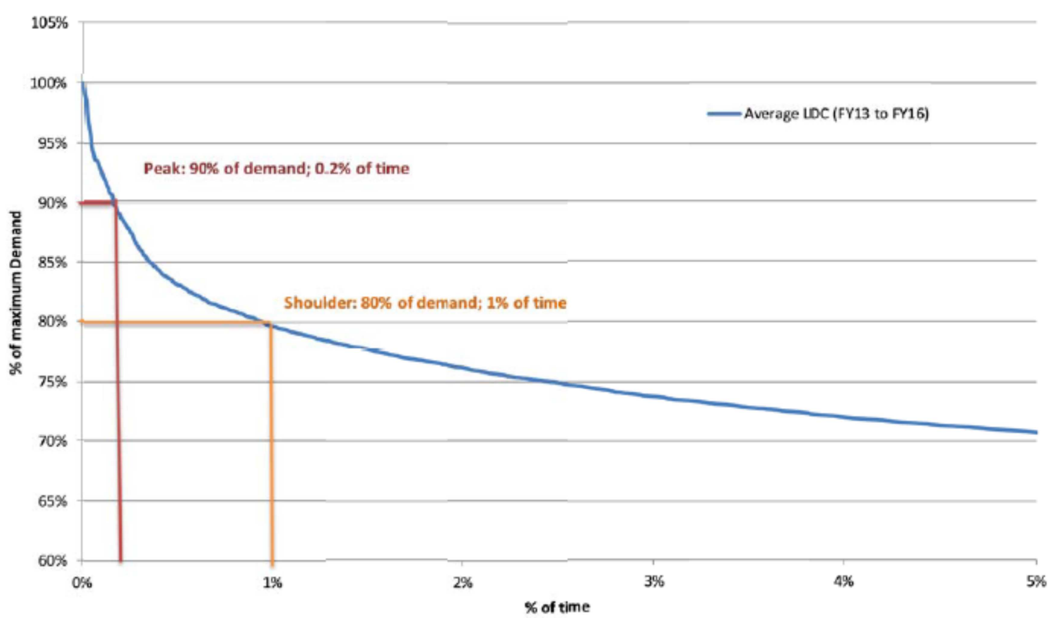
153 Alternatively, distributors consider expected levels of demand when deciding asset capacity in replacement capital expenditure decisions. See chapter 7 for further discussion.

using the highest demand intervals in recent years. Endeavour Energy stated its peak period contains data points within 10 per cent of the peak demand for each year. The shoulder period contains the data points between 10 per cent and 20 per cent of the peak demand interval for that year.[154]

Endeavour Energy explained the 10 per cent and 20 per cent thresholds are related to network planning. Endeavour Energy stated its planners begin investigations into an asset when the proportion of time that asset exceeds its firm rating is greater than 1 per cent. This includes considering augmentation capex or demand management options.[155]

Because Endeavour Energy's tariffs apply at a network level, it uses the network load duration curve as indicative of likely demand at an asset level (see Figure 8-8). Figure 8-8 shows Endeavour Energy's highest demand points are within 20 per cent of maximum demand for one per cent of the time. Its highest demand points are within 10 per cent of maximum demand for 0.2 per cent of the time.[156]

Figure 8-8 Endeavour Energy average network load duration curve



Source: Endeavour Energy, Tariff structure statement: Explanatory statement, 4 October 2016, p. 47.

Note: The load duration curve above is an average of the annual curves for the 2012–13 to 2015–16 years. Endeavour Energy used the average of multiple years to mitigate the impact of abnormal weather impacts in any given year. Endeavour Energy, Response to information request: Charging windows issues, 24 November 2016.

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[154] Endeavour Energy, *Tariff structure statement*, 27 November 2015, p. 72.

[155] Endeavour Energy, *Tariff structure statement: Explanatory statement*, 4 October 2016, p. 46.

[156] Endeavour Energy, *Tariff structure statement: Explanatory statement*, 4 October 2016, p. 46.

We consider Endeavour Energy's approach is a useful starting point as it establishes a link between its charging windows and network utilisation (it does this indirectly via its planning criteria).

In addition, Endeavour Energy's approach uses an objective method to determine the thresholds between peak, shoulder and off-peak hours. By comparison, evidence based on demand levels alone does not provide as clear a guide on the thresholds between the peak, shoulder and off-peak hours. As a result, it was not always clear how distributors determined the thresholds between charging windows, which is not as transparent.

We emphasise Endeavour Energy's approach can be a useful starting point when considering approaches for the next round of tariff structure statements. We encourage Endeavour Energy (and other distributors) to explore ways to improve the use of load duration curves (should distributors adopt or continue to use them) in future tariff structure statements.[157] Alternatively, distributors may choose to explore other approaches to incorporate information on network utilisation to determine charging windows.

Developing an industry approach for charging windows

The Energy Networks Association stated it will discuss with its members options for developing charging windows.[158]

We support the ENA's initiative to consult with its members regarding methods for establishing charging windows. We consider it is a good opportunity for the industry to discuss and explore ways to improve methods for determining charging windows—including its place in the broad context of tariff reform. This could potentially lead to more rigorous and objective methods to setting charging windows. Distributors may then utilise findings from these discussions to refine their methods to suit their individual circumstance. This could in turn lead to more cost reflective tariffs.[159]

The ENA also stated to us it will discuss with its members the prospect of developing an 'industry approach' for charging windows.[160] This does not mean that all distributors would have the same charging windows. Rather, that a consistent analytical or conceptual approach is used to determine the charging windows specific to each particular network.[161]

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[157] See section 8.2 of AER, *Final decision: Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017.

[158] ENA, *Submission: Australian Energy Regulator draft decision on tariff structure statement proposals*, 7 October 2016, p. 4.

[159] NER, cl. 6.18.5(g).

[160] ENA, *Submission: Australian Energy Regulator draft decision on tariff structure statement proposals*, 7 October 2016, p. 4; AER, *File note - Non-Victorian TSS - Discussion with ENA*, 17 October 2016 (AER reference: D16/140751).

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

At this stage, it is unclear to us whether it is necessary, or even desirable, to develop an industry approach for charging windows. We acknowledge an industry approach has benefits. It could aid stakeholders to more easily understand the reasons for a distributor's proposed charging windows, and the reasons for differences with other distributors' charging windows.[162]

On the other hand, adopting a common approach poses the risk of 'settling' into this approach and slowing innovation in this area. As moving from demand based to utilisation based approaches to determining charging windows would be new for most distributors, it may be useful for different distributors to innovate and adopt different methods. The strengths and weaknesses of these different methods could then be assessed at a later stage, with a common industry approach a potential longer term goal which is informed by these earlier innovations. An industry approach should therefore not dampen the incentive for individual distributors from innovating on methods to determine charging windows.

If the ENA and its members consider developing an industry approach is appropriate, they should also keep in mind the transitional nature of the tariff reform process. That is, distributors are at various stages of transition. We consider an industry approach, if developed and adopted, should have the flexibility to accommodate individual distributors' circumstances as well as the dynamic nature of tariff reform.

Charging windows

Our suggestions on refining charging windows are specific to each distributor. This is because the distributors introduced various levels of reform to their charging windows in their revised tariff structure statements. In addition, they all have slightly different patterns of network utilisation. As examples, the improvements that we would expect to see in some of the distributors' future tariff structure statements include:[163]

- Narrowing peak windows—Some stakeholders consider the peak window is too long, so customers have limited opportunity to access lower prices, and less incentive to respond to the peak price signal. We consider there is scope for distributors to narrow their peak hours to better target times of network congestion. For example, many networks show a narrower peak period in winter compared to summer. These networks can consider introducing different peak hours for their winter and summer months.
- Introducing or expanding seasonal differences—Many networks exhibit highly seasonal demand patterns. As we noted earlier, many networks have narrower winter peak periods compared to summer. Many networks also show a marked decrease in demand levels in non-summer and non-winter months. However, most distributors are typically summer-peaking and/or winter-peaking. These networks

[162] NER, cl. 6.18.5(i).

[163] NER, cl. 6.18.5(f).

can potentially remove peak hours during those non-summer and non-winter months and only include shoulder and off-peak periods.[164]

- Introducing locational differences within a network—Currently, most charging windows are based on system wide network data. However, this can mask important regional differences within a network. For example, a network might be summer peaking overall, but contain alpine regions which are winter peaking. In these cases, different charging windows could be applied to the alpine and non-alpine regions. Alternatively, regions within a network which are dominated by residential demand might have very different load characteristics to regions which are dominated by large industrial demand. Distributors should consider whether there is a case for regional differences in their charging windows.

Peak demand measurement in demand charges

Most distributors proposed some residential or small business tariffs with a demand charge in this first round of tariff structure statements. The distributors proposed different ways to measure a customer's demand for the purposes of calculating demand charges (see our summary below). The measures of demand each distributor proposed are generally consistent with their practices in recent pricing proposals and so represent an incremental change in tariff structures. We therefore accepted the distributors' proposed measures of demand in this initial phase of tariff reform as they are consistent with the customer impact principle.[165]

However, we encourage distributors to investigate alternative measures of demand for the next round of tariff structure statements having regard to each measure's ability to:

- send price signals to customers that are more closely aligned with peak demand and utilisation on the network, rather than aligned with the individual customer's peak demand[166]
- enable customers to respond to price signals[167]
- avoid or manage the potential for a customer to face 'bill shock'.[168]

A measure of demand proposed by several distributors is to charge customers based on the highest use recorded in any 30 minute period during the peak charging window during the month.[169]

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[164] To avoid confusion, we do not use the terms 'spring' and 'autumn'. Some distributors define summer as the period between November and March inclusive, which includes months that are 'officially' spring and autumn (see http://www.australia.gov.au/about-australia/australian-story/austn-weather-and-the-seasons).

[165] NER, cl 6.18.5(h).

[166] NER, cl 6.18.5(a).

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

[168] NER, cl 6.18.5(h).

[169] The distributors whose demand tariffs generally charge on this measure include ActewAGL, Essential Energy, AusNet Services, CitiPower and Powercor.

Other distributors similarly use the highest recorded demand, but over a longer time period. Ausgrid's demand tariffs charge for certain business customers is based on the peak demand recorded in any 30 minute period during the peak charging window in the previous 12 months.[170] Jemena's demand tariffs for existing small businesses charge customers based on the peak demand recorded during the peak charging window from the past two months.[171]

An alternative approach to using a single peak demand point is to average a customer's top several demand periods during the month (that fall within the peak charging window). We observe Ergon Energy proposed to average the top four highest demand periods as the basis for calculating the demand charge for its residential customers. Essential Energy also has one tariff which calculates the demand charge based on the 'average daily time of use demand for peak, shoulder and off-peak periods for the month'.[172]

As previously stated, we accept the various measures of demand proposed by the distributors in this first round of tariff structure statements, including the use of a single 30 minute period. However, we also consider there are potential benefits in using an averaging approach, such as Ergon Energy's, or other approaches.

We would be interested in working through this issue with the industry and stakeholders in the lead up to the next round of tariff structure statements.

It is not an individual customer's peak demand that drives network costs, but the extent to which that customer's demand contributes to times of network congestion. Several distributors' approaches only record a customer's highest 30 minute demand period if it falls within the peak charging window. However, the individual customer's highest demand may not coincide with the times the network is congested. An averaging approach may increase the probability that a customer's highest demand will coincide with the day, or days, on which the network is congested.

We encourage distributors to collect data during this first tariff structure statement period that demonstrates if the majority of customers' peak demand occurs at the same time the network also experiences congestion. This should provide a useful basis for determining if the second and subsequent tariff structure statements should make a change to averaging a customer's highest demand days, similar to Ergon Energy's approach.

The use of a single period or averaging approach may also have an impact on a customer's ability to respond to price signals. Price signals aim to elicit an informed and considered response by consumers. If a customer has automatic appliances (for example, air-conditioner or battery storage programmed to respond to peak demand periods) then responding to price signals might be straight forward.

170 Ausgrid, *Revised tariff structure statement: Appendix A*, 4 October 2016, pp. 112–125.

171 Jemena, *Tariff structure statement*, 29 April 2016, p. 30.

172 Essential Energy, *Tariff structure statement*, 4 October 2016, p. 16.

In the absence of automatic appliances, it may be more difficult for customers to mitigate the effects of one-off spikes in demand, especially residential and small business customers. This may be the case, especially initially, as customers may need time to become more familiar with demand signals and the amount of electricity different appliances consume. If a customer’s top 30 minute demand window coincides with the peak period in one month, for example if they turn on several appliances at the one time during the peak window, they will have a heightened incentive to understand their electricity usage the following month to avoid a repeat situation. Alternatively, an averaging approach might assist a customer in responding within the month, rather than waiting until the next month. This is because the customer can shift their usage outside the peak period or lower their usage during the peak period for the rest of the month to constrain their average maximum demand. For similar reasons, an averaging approach may also assist a customer to avoid or manage ‘bill shock’ if the network tariff structure is also reflected in the customer’s retail tariff.

A Distributors' customer consultation and customer impact analysis

This section sets out the consultation process that Energex and Ergon Energy undertook when developing their 2017–20 tariff structure statements and how they responded to customer and stakeholder feedback. The Rules require that distributors consult with their customers in order to help them understand the new tariffs and thereby how they might mitigate the tariffs' impact on them.[173]

The Rules require distributors to describe how they have consulted with their customers and retailers, and explain how they have addressed concerns raised as a result of this engagement.[174] We are of the view that distributors' stakeholder engagement contributes to the achievement of compliance with the distribution pricing principles and the national pricing objective.

A.1 Customer consultation and impact analysis

Below we have set out how distributors responded to what stakeholders asked.

We find that the consultations undertaken over the last few years to develop each distributor's tariff statements have been wide ranging, generally clear and understandable and that stakeholders comments have been taken up, where possible, in development of the statements.

With many issues to cover, and in some cases complex material to convey, it is not possible for 100 per cent of issues raised by either stakeholders or the networks to be agreed, much less implemented. Inevitably there are trade-offs between the needs of different customer groups and tariff classes, and within tariff classes.

Both Energex and Ergon Energy have consulted with stakeholders throughout the process of developing the Tariff Structure Statements. They have held workshops and published consultation papers. This has been documented in the *Energex Tariff Structure Statement – Explanatory notes 1 July 2017 to 30 June 2020* Appendix 2 and the *Ergon Energy Supporting Information Revised Tariff Structure Statement 2017 to 2020* Appendix A.

Energex

We consider Energex undertook significant stakeholder consultation processes in developing its tariff structure statement proposal. Energex's customer consultation included:[175]

173 NER, clauses 6.18.5(h)(2) and (3) and 6.18.5(i)(1) and (2).

174 NER, cl 6.8.2(c1a).

175 Energex, *Tariff Structure Statement – Explanatory Notes, 1 July 2017 to 30 June 2020*, 4 October 2016, pp. 68-74.

- discussion papers and consultation papers
- conducted workshops and meetings
- Customer Impact Statement
- coordinated targeted engagement through industry partners
- e-newsletters.

Table A-1 below outlines Energex's consultation as described in its tariff structure statement.

Table A-1: Stakeholders' messages and distributors' responses

Topic	What stakeholders said	How Energex responded
Pricing principles	Stakeholders valued consistency in network structures.	Energex has had to balance simplicity against other pricing principles such as cost-reflectivity and customer impact.
Case for demand tariffs	Stakeholders were generally supportive of demand tariffs, which are considered to be more cost reflective. However there was some concern that demand tariffs would not be understood by customers and would need to address the customer impact principle.	Energex explored alternatives to demand tariffs, however these were not considered suitable at this stage. Time of use tariffs have thus far had limited uptake. Critical peak pricing is too complex and requires technology that is not currently widely available in Queensland.
Use actual demand data	Stakeholders did not support the use of inferred demand data.	Energex intends to use actual data when implementing tariff reform.
Tariff structure	Residential customers did not support the retention of a daily supply charge as part of the proposed demand tariffs. They supported retaining a usage charging parameter.	Energex believe that retaining a daily supply charge will offer a greater level of stability in customer bills. Supply charges will increase by CPI, corresponding to a neutral change in real terms. Retaining the usage charging parameter in demand tariffs will allow a better transition.
Peak period	Stakeholders generally supported the option of measuring demand peaks within set periods. They were in favour of the peak periods being limited to week days from 4pm to 8pm.	Energex analysis supports the proposed window of 4pm to 8pm, weekdays only. Public holidays will be excluded.
Seasonality	Stakeholders acknowledged the presence of summer and winter peaks in south east Queensland. Therefore a seasonal demand charge could not be justified.	Energex does not support the use of seasonality. This reduces unnecessary complexity.
Load control	Stakeholders strongly supported the retention of load control tariffs and demand management.	Existing load control tariffs will be retained.
Maximum or average of four highest demand readings	Stakeholders gave mixed feedback on whether or not the average of the top four peaks should be used to measure demand. Single peak measurement was thought to impact customers for a one-off high demand day.	Energex proposes to charge for demand based on the single maximum demand in the month. This provides greater simplicity in understanding how the demand charge will be derived.

Opt-in/ voluntary tariff	Concerns were raised about implementing a mandatory roll out of advanced meters. Customer representatives supported an opt-in approach until 2020.	Energex prefers an opt-in approach to tariff reform until 2020. Energex will gather evidence from the Real Time Tariff Study for cost reflective tariffs after 2020.
Customer impact modelling	Stakeholders have requested an assessment of the impact on customers of the proposed tariff reform.	Energex released a Customer Impact Statement in September 2015 and will update it as required.
Understanding demand tariffs	Stakeholders expressed concern that the demand tariffs will be complicated to understand. Responses highlighted the need for broad and targeted education programs.	Energex has planned a comprehensive communication strategy which includes working with community stakeholders. The real Time Tariff Study will help build customers understanding of demand charging, enable customers to make informed decisions about network usage, assess impacts and address barriers to tariff adoption.

Ergon Energy

We consider Ergon Energy undertook significant stakeholder consultation processes in developing its tariff structure statement proposal. Ergon Energy's customer consultation included:[176]

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

[176] Ergon Energy, *Tariff Structure Statement – Supporting Information, 1 July 2017 to 30 June 2020*, 4 October 2016, pp. 23-34.

Table A-2 below outlines Ergon Energy's consultation as described in its tariff structure statement.

Table A-2: Stakeholders' messages and distributors' responses

Topic	What stakeholders said	How Ergon Energy responded
Rise in electricity prices	Stakeholders expressed concern over electricity prices over recent years.	Ergon Energy has focused on ensuring it can deliver for the best possible price. Over the next regulatory period, its expenditure is forecast to be more than a billion dollars less.
Remove cross subsidies	Tension between the need to remove cross subsidies as early as possible and the need for customers to have more time to be able to respond to these changes.	2016-17 will be the foundation year for the Ergon Energy’s position on tariffs for 2017-2020. For this period, the tariff structures are planned to be relatively stable. This allows customers to build a greater understanding of the new options and for Ergon Energy to promote their take up.
Voluntary tariffs	Stakeholders support the new demand-based, seasonal time-of-use tariffs to be introduced as voluntary tariffs. Some stakeholders acknowledge that there is no visibility of the network tariff in the regulated retail tariff.	Introducing new tariffs as optional tariffs allows a way to progress the reforms gradually. They can be piloted with different customer segments. Customers who are unsure will be able to stay with their existing tariff.
kVA and kVAr charging for large customers	While the rationale for kVA charging is understood, stakeholders were wanting lead times for the implementation. This was to allow time to respond and improve a site’s power factor.	Ergon Energy notified ICC and CAC customers at least 12 months lead time to understand and engage with Ergon Energy on the changes. Further stakeholder engagement will be undertaken for applying these charges to customers using less than 4 GWh p.a.
Benefits to customers	Customers need to be provided with clear rationale for the tariff reforms and evidence of longer term benefits to customers.	Ergon Energy’s objective is to deliver fairer, more equitable price signals and meet everyone’s needs in the future for the best possible price. Energeia has quantified the ‘cost of inaction’ of no tariff reform against alternative approaches to cost reflective tariffs.
Price impacts	There is limited information around the potential price impacts by customer segment, particularly the impact over the summer months.	Ergon Energy accepts that educating customers on the likely impact on their bills is necessary for customers to elect cost reflective tariffs. Obstacles have been a lack of segment and demographic data to identify ‘winners and losers’ from the tariff. Challenges also exist around the extrapolation of the network charge into a regulated retail tariff.
Bill protections	That there are adequate bill protections for vulnerable households who move to demand-based tariffs.	Given the current Uniform Tariff Policy arrangements, employing bill protection measures at the network level are unlikely to be satisfactory. These are best incorporated in the retail tariffs.
Peak demand periods	Stakeholders questioned the actual periods of peak demand on the network. There is also concern that customers could experience ‘summer bill shock’.	Energex has set the periods for the peak demand charges from detailed analysis of the indicative daily/annual load profiles. Not aligning tariffs with the actual peak demand periods would interfere with the pricing signal. Customers on these new tariffs have substantial reductions in the usage charge compared to

		legacy tariffs.
Supporting technology (meters)	The required meters need to be affordable so that customers can respond to price signals appropriately. It was noted that Ergon Energy could subsidise the shift to smart meters where there are network constraints.	Ergon Energy will participate in future government and regulatory discussions on the roll out of smart meters, including the treatment of renters and other specific customer segments. It will look at incentivising the take-up of demand-based tariffs in the constrained areas as part of the targeted demand management program.
Tariff features	Stakeholders have shown concern over the incremental cost as the basis of cost reflective pricing signals and whether it should be location specific.	Ergon Energy has outlines the unique nature of its network, customer base and pricing arrangements.
Fixed charges	There is general support for a reduction in fixed charges for the demand-based network tariffs.	This is a feature of the seasonal time-of-use demand tariff. Other tariffs and charges are required to reflect the fixed or sunk costs associated with the investment in the network.
Averaging method	There is general support for the averaging method used to calculate the demand tariff, however there was concern over the level of complexity.	This calculation has been simplified by applying the same methodology of averaging for both summer and non-summer months.
Solar customers	The solar industry is concerned about the impact of demand-based tariffs on solar customers.	Ergon Energy has not sought to classify solar customers separately from customers without solar. However, it has looked at the impact of different tariff structures against a sample of customers and the incentives of that tariff to uptake solar and storage.
Controlled load tariffs	Stakeholders have questioned how the controlled load tariffs work in the suite of tariffs to complement the new cost reflective tariffs.	Ergon Energy has started a process to rebalance these tariffs. This will see the rates developed based on residual recovery principles, as these loads do not impact peak demand (so they do not have to recover any LRMCs).
Uniform Tariff Policy	The Uniform Tariff Policy and how this subsidisation through the regulated retail tariffs impacts the rates applied to the default and demand-based tariffs now and in the coming years. It may be necessary for the Queensland Government to consider policy positions.	The timing and degree of impact of Ergon Energy's network tariffs on the regulated retail tariffs is subject to the QCA's annual pricing determination. The Uniform Tariff Policy, how it is designed and if it should be targeted, is a topic under review by the Queensland Productivity Commission. Nevertheless, Ergon Energy was to make sure that its network tariff structures are efficient.
Retailers	Stakeholders have raised how retailers will reflect the network tariff structures and rates in their retail tariffs. This includes whether they should be required to show the network charges on the bill.	The QCA has supported Ergon Energy's reform path. We anticipate that this will allow Ergon Energy Queensland Pty Ltd (retail) to offer tariff choices that reflect the changes in network tariffs.
Pricing zones	Stakeholders raised questions about Ergon Energy's pricing zones, most notably using the East Zone to develop the tariff structures that apply to the West and Mount Isa Zones.	Ergon Energy develops prices for three different pricing zones. These are based on geographic areas of the network where costs are broadly similar. It is not seen as necessary to differ the tariff structures by zone, only the rates.

B AER consultation

This appendix details our consultation with stakeholders throughout the tariff structure statement approval process.

B.1 Issues paper, public forum, submissions and draft decision

In March 2016, we published an issues paper on the Tariff Structure Statement proposal submitted by Energex and Ergon Energy. This summarised key aspects of the proposal and highlighted issues we considered relevant to our assessment. We received written submissions in response to our issues paper from Energy Consumers Australia (ECA), National Seniors Australia, AGL Energy Ltd, Canegrowers and Sapere Research Group, Lumo/Red Energy, Energex, Origin Energy, Trade Coast Central, Energy Australia, Energy Networks Association (ENA), Ergon Energy, Queensland Farmers' Federation (QFF) and Local Government Association of Queensland (LGAQ).

In April 2016, we hosted a public forum to discuss Energex and Ergon Energy's tariff structure statement proposal and invited interested parties to provide their views. Several stakeholders attended including customer groups, Queensland Government representatives and retailers.

On 2 August 2016, we made a draft decision to approve Energex and Ergon Energy's proposed tariff structure statement. We invited further submissions from stakeholders and highlighted areas where the proposed tariff structure statement required more explanation. Under the Rules, a distributor may only make revisions to its tariff structure statement to address matters raised by our draft decision.

In response to stakeholder submissions, we did ask Energex to review its peak charging windows for business customers. We also requested Ergon Energy give consideration to Canegrowers submissions about charging windows for business customers that would affect irrigators and cane growers.

After the draft decision we also held a discussion with National Seniors Association and the Queensland Council of Social Service (QCOSS) in respect of key features of the Queensland distributors' tariff proposals and the draft decision.

Energex and Ergon Energy submitted revised tariff structure statements in October 2016. We published the revised proposal and invited submissions from stakeholders.

In response to our draft decision and Energex and Ergon Energy's revised tariff structure statement, Local Government Association of Queensland (LGAQ), Origin Energy, the Clean Energy Council, Trade Coast Central and the Energy Networks Association provided written submissions. Canegrowers and their consultants Sapere provided multiple submissions. Ergon Energy's consultants Frontier Economics and Energeia provided responses to the Canegrowers' submissions.

We have held numerous meetings with stakeholders to discuss the tariff structure statement draft decisions for all distributors, including meeting with Canegrowers and their consultant Sapere in associated with Ergon Energy's tariff structure statement and Trade Coast Central in regards to Energex's tariff structure statement. We also arranged a meeting with Canegrowers, Sapere, Ergon Energy, Frontier Economics and Energeia. The Queensland Department of Energy and Water Supply came along as observers.

On 28 February 2017, we make a final decision to:

- approve Energex's revised tariff structure statement proposal, subject to minor editorial changes made to the document.
- approve Ergon Energy's revised tariff structure statement proposal, subject to minor editorial changes made to the document.