DRAFT DECISION

Ergon Energy
Distribution Determination
2020 to 2025

Attachment 18
Tariff structure statement

October 2019

AUSTRALIAN
ENERGY
REGULATOR

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Note

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

The draft decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
capex	capital expenditure
CCP14	Consumer Challenge Panel, sub-panel 14
CPI	consumer price index
distributor	distribution network service provider
DUoS	distribution use of system
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER or the rules	national electricity rules
NSP	network service provider
opex	operating expenditure
RAB	regulatory asset base
repex	replacement expenditure
RIN	regulatory information notice

Glossary of terms

Term	Interpretation
Apparent power	See kVA
Anytime demand tariff	A tariff incorporating a demand charge where the demand charge measures the customer's maximum demand at anytime (i.e. not limited to within a peak charging window).
CoAG Energy Council	The Council of Australian Governments Energy Council, the policymaking council for the electricity industry, comprised of federal and state (jurisdictional) governments.
Consumption tariff	A tariff that incorporates only a fixed charge and usage charge and where the usage charge is based on energy consumed (measured in kWh) during a billing cycle, and where the usage charge does not change based on when consumption occurs. Examples of consumption tariffs are flat tariffs, inclining block tariffs and declining block tariffs.
Cost reflective tariff	Consistent with the distribution pricing principles in the NER, a cost reflective distribution network tariff is a tariff that a distributor charges in respect of its provision of direct control services to a retail customer that reflects the distributor's efficient costs of providing those services to the retail customer. These efficient costs reflect the long run marginal cost of providing the service and contribute to the efficient recovery of residual costs.
Declining block tariff	A tariff in which the per unit price of energy decreases in steps as energy consumption increases past set thresholds.
Demand charge	A tariff component based on the maximum amount of electricity consumed by the customer (measured in kW, kVA or kVAr) which is reset after a specific period (e.g. at the end of a month or billing cycle). A demand charge could be incorporated into either an anytime demand tariff or a time-of-use demand tariff.
Demand tariff	A tariff that incorporates a demand charge component.
Fixed charge	A tariff component based on a fixed dollar amount per day that customers must pay to be connected to the network.
Flat tariff	A tariff that incorporates a flat usage charge component.
Flat usage charge	A tariff component based on a per unit charge (measured in kWh) that does not change regardless of how much electricity is consumed or when consumption occurs.
Inclining block tariff	A tariff in which the per unit price of energy increases in steps as energy consumption increases past set thresholds.
Interval, smart and advanced meters	Used to refer to meters capable of measuring electricity usage in specific time intervals and enabling tariffs that can vary by time of day.
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

Term	Interpretation
	power when the current and voltage are not in phase.
kVAr	Also called reactive power and is power used to maintain the electromagnetic fields of equipment. Low power factors are associated with higher levels of reactive power.
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 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	The network tariff that is charged to the customer's retailer (or in limited circumstances, charged directly to large customers) for use of an electricity network. A single tariff may comprise one or more separate charges, or components.
Tariff 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 demand tariff (ToU demand tariff)	A tariff incorporating a demand charge where the demand charge measures the customer's maximum demand during a peak charging window. A ToU demand charge might also include an off-peak demand charge or minimum demand charge, and may include flat, block or time-of-use energy usage charges.
Time-of-use energy tariff (ToU energy tariff)	A tariff incorporating usage charges with varying levels applicable at different times of the day or week. A ToU energy tariff will have defined charging windows in which these different usage charges apply. These charging windows might be labelled the 'peak' window, 'shoulder' window, and 'off-peak' window.
Usage charge	A tariff component based on energy consumed (measured in kWh). Usage charges may be flat, inclining with consumption, declining with consumption, variable depending on the time at which consumption occurs, or some combination of these.

18 Tariff structure statement

This attachment sets out our draft decision on Ergon Energy's tariff structure statement to apply for the 2020–25 regulatory control period.

Our draft decision is to not approve Ergon Energy's proposed tariff structure statement, as we are not satisfied that it complies with the distribution pricing principles in the Rules.[1] Although we are satisfied that parts of its tariff structure statement contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective, we consider that some elements of the tariff structure statement require amendment and further detail.

A tariff structure statement applies to a distributor's tariffs for the duration of the regulatory control period. It should describe a distributor's tariff classes and structures, the distributor's policies and procedures for assigning customers to tariffs, the charging parameters for each tariff, and a description of the approach the distributor will take to setting tariff levels in annual pricing proposals. It is accompanied by an indicative pricing schedule.[2] A tariff structure statement provides consumers and retailers with certainty and transparency in relation to what network tariff structures will be charged to retailers for different types of customers over the five year period that it applies.

It is important to note that distributors directly charge retailers for the network services provided to end-customers and there is no obligation on retailers to pass the network tariff structure through to their end-customers. The structure of retail prices should be determined in the market by retailers responding to consumer preferences and competitive pressures (or determined by regulators where retail price regulation applies). The key consideration is that distributors provide retailers with better price signals over the costs associated with the provision of electricity network services. This will ensure that retailers make informed decisions about how best to manage the financial risks under more cost reflective network pricing. The competitive retail market helps promote an outcome where retailers make these decisions in a manner that takes into account the preferences of their end-customers. In some instances, retailers could rely on non-price measures, such as well targeted demand management initiatives, to manage these commercial risks. In other situations retailers may be encouraged to pass through cost reflective network tariff structures to end-customers if they believe that these customers are well placed to respond to these price signals and potentially be rewarded for doing so. At present, it is more common for retailers to pass through the cost reflective network tariff structures to large business customers, than for residential or small business customers.

1 NER, cll. 6.12.2(k) and 6.12.1(14A).

2 NER, cl. 6.18.1A (e).

18.1.1 Background to this decision

This is Ergon Energy's second tariff structure statement and applies to the 2020–25 regulatory control period. It must comply with the distribution pricing principles in the Rules.[3] These pricing principles require distributors to transition to cost reflective tariffs and, in doing so, to account for impacts on consumers.

In each of our final decisions on distributors' first tariff structure statement (including Ergon Energy's tariff structure statement for 2017–20), we identified that distributors should make further improvements in the following areas in the second round of tariff structure statements:

- Greater integration between network pricing, network planning and demand management strategies.
- Adoption of opt-out (rather than opt-in) assignment policies to improve the previous slow pace of transition to cost reflective tariffs.
- Methodology for estimating long run marginal cost.
- Inclusion of replacement capital within a distributor’s long run marginal cost estimates.
- Reconsideration of the design of demand tariff (based on a single monthly 30 minute window) that was the most common design adopted by distributors.
- Refinements to charging windows and the methods used to develop charging windows.[4]

We recognise that Ergon Energy has made progress in addressing these issues, such as the adoption of a cost reflective default tariff for residential and small business customers and exploration of an alternative estimation methodology for long run marginal cost.

It is also the case, however, that EnergyQueensland did not submit a complete TSS proposal in January 2019, as required under the NER. EnergyQueensland consulted further with its stakeholders in subsequent months and further information was provided. This culminated in an updated TSS proposal to the AER on 14 June 2019 and this is the basis of our assessment in this draft decision. These matters are discussed in more detail below.

While Energex and Ergon Energy submitted separate updated tariff structure statements to the AER on 14 June 2019, we note that these proposals are based to a large extent on a common network tariff strategy adopted by their parent company,[5] EnergyQueensland. As a result, our decision and reasons are largely common across the Energex and Ergon Energy

[3] NER, cl. 6.18.5.

[4] AER, *Final Decision: Energex and Ergon Energy—Tariff Structure Statements—Final Decision,* February 2017, p. 20.

[5] Note that the key exception to the common tariff strategy is Ergon Energy's proposal to introduce an opt-in time of use energy tariffs for customers on transitional regulated retail electricity tariffs.

draft decisions and it will be sufficient for most stakeholders to only read one of our decisions.[6]

Like South Australia, Queensland is at the forefront of the consumer lead and technology driven transformation of the energy sector with the highest number of roof-top solar PV systems installed in the National Electricity Market (NEM). This transformation is expected to continue with forecast growth in installation of solar PV systems. There is also expected to be a significant uptake over the long term of batteries and electric vehicles, albeit from a low base. For more information on the current and forecast penetration of Distributed Energy Resources (DER) see appendix A.

The rapid transformation of the energy sector is changing the way that consumers are using the electricity network. The Queensland distributors consider this transformation has resulted in an exacerbation of the inherent cross subsidies under existing legacy flat tariffs, particularly in regard to solar PV customers.[7][8] As a consequence, the Queensland distributors consider there is an urgent need to introduce demand tariffs as a stepping stone to its longer term solution of capacity tariffs.

The stakeholders that have participated in the engagement process for the Queensland distributors' tariff structure statements are not wholly convinced by this rationale for tariff reform.[9] They do not have a clear understanding of the nature and magnitude of this cross subsidy problem, nor how the complicated suite of tariff reforms proposed by the Queensland distributors will address this problem. We note that the Queensland distributors have not yet published adequate customer impact analysis, which has exacerbated stakeholder concerns over the potential for the proposed tariff reforms to have a detrimental long term impact on certain customers. Particularly those with high energy consumption and/or high demand. To their credit, the Queensland distributors have agreed to engage CSIRO and UNSW to undertake detailed distributional bill impact analysis of its proposed tariff reforms. Unfortunately, this analysis is not yet available.

We recognise that the Queensland distributors have to some extent tried to respond to the feedback of their stakeholders by making changes to their tariff strategy. While these efforts have generally been appreciated by stakeholders, it has been difficult for some stakeholders to understand whether these changes were a result of feedback received, or represented a

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6 It should also be noted that our assessment of Energex and Ergon Energy's TSS proposals has taken into account their unique circumstances. For example Ergon Energy currently has seasonal pricing in its ToU and demand tariffs, whereas Energex does not. Ergon Energy also has a legacy inclining block tariff which Energex does not.

7 Ergon Energy, *Overview of tariff structure statement - 2020–25*, June 2019, p. 8.

8 Under the flat tariff, a customer can lower their network bill by installing a solar PV system because they can reduce their energy consumption from the grid (basis of the network bill) by consuming some of the energy generated by the solar PV system. The installation of a solar PV system does not materially reduce the customer’s peak demand in the evening.

9 ECA, *Submission to AER Issues paper - 2020–25 Regulatory Control Period - Energex and Ergon Energy*, June 2019.

more fundamental rethink by the Queensland distributors of their tariff strategy.[10] This has added to the frustration of stakeholders.

For example, the Queensland distributors' proposal to introduce new controlled load tariffs was initially welcomed by irrigators[11] until they realised that these tariffs were only available to customers in limited areas of Ergon Energy's electricity network, where localised congestion is expected in the foreseeable future. In response to the concerns from agricultural stakeholders, the Queensland distributors expanded the availability of the discounted controlled load tariffs to the whole of its network, but has made these tariffs less attractive by reducing the level of discount.[12]

The Queensland distributors submitted their initial tariff structure statements to the AER in January 2019, which was the timeframe required by the Rules.[13] Our staff level assessment of these proposals found them to be unclear in many respects and lacked supporting evidence and analysis.

At that time the Queensland distributors indicated that their previous tariff strategy for the 2020–25 period that was largely based on its “Lifestyle Package” pricing plans on which it had been working for two years or more, was changed in late 2018. This decision was made mainly in response of stakeholder concerns over the complexity of the “Lifestyle Package” pricing plans which required that retailers acting on behalf of customers select a specific level of network capacity in advance of the billing period.[14]

In February 2019, the Queensland distributors initiated an intensive stakeholder consultation process intended to address the missing elements identified in their January 2019 tariff structure statements.[15] The Queensland distributors submitted partial updates to their January proposed tariff structure statement in the following months. They also developed new tariff reform proposals at this time, such as the inclining block tariff. In response to an AER request, the Queensland distributors submitted a complete updated tariff structure

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10 QCOSS, *Etrog Consulting report prepared on behalf of QCOSS - Energy Queensland: TSS*, April 2019, p. 4.

11 http://www.canegrowers.com.au/page/media/media-releases/2018/irrigation-tariff-trial-extension-a-small-but-welcome-step

12 The lesser price reward reflects that by broadening their availability to unconstrained areas of the network reduces the economic value of associated load control.

13 This document is available from our website, see link below: www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020–25/proposal#step-60838

14 For more information on this issue refer to Energy Queensland correspondence to the AER on 14 February 2019. This document is available from our website, see link below: www.aer.gov.au/system/files/Ergonper cent20Energyper cent20-per cent2014per cent20Februaryper cent20tariffper cent20structureper cent20statementper cent20furtherper cent20explanationper cent20-per cent20Februaryper cent202019.pdf

15 For more information, refer to correspondence from Energy Queensland. This document is available from our website, see link below: www.aer.gov.au/system/files/Ergonper cent20Energyper cent20-per cent2014per cent20Februaryper cent20tariffper cent20structureper cent20statementper cent20furtherper cent20explanationper cent20-per cent20Februaryper cent202019.pdf

statement and accompanying indicative price schedule on 14 June 2019.[16] However, this indicative pricing schedule was incomplete with additional information required which was submitted on 28 June 2019.[17]

While the Queensland distributors subsequently proposed to again further update their proposed tariff structure statement, we indicated it was not appropriate for distributors to be continually changing their proposals in the lead up to the draft decision and the AER would not accept any more updates this late in the process. This was required to ensure that we had adequate time to assess whether the proposed tariff structure statement complies with the distribution pricing principles in the Rules and to engage with our stakeholders on the key aspects to our draft decision. As a result, we have based our draft TSS decision on the proposed tariff structure statement submitted to the AER on 14 June 2019.

The Queensland distributors will now have an opportunity to formally revise their proposed tariff structure statement in response to this draft decision. We highlight that under the propose-respond framework, at this stage in the process, a distributor may only make revisions to its tariff structure statement so as to incorporate the substance of any changes required to address matters raised by our draft distribution determination or our reasons for it.[18]

Over the period between early January and mid-June 2019 the Queensland distributors held a large number of stakeholder meetings, workshops (deep dives) and forums. At times, stakeholders have attended these events weekly or fortnightly. To their credit, these stakeholders actively participated in this engagement process, although at considerable effort and cost.[19]

Over this timeframe we have engaged with stakeholders through our attendance of a large number of forums, workshops and one-on-one meetings. We have liaised on a regular basis with the Queensland distributors, Queensland Department of Natural Resources, Mines and Energy, the Queensland Competition Authority, Pioneer Valley Water irrigation scheme, Queensland Canegrowers, other irrigation groups, farming groups, Energy Consumers Australia and the Consumer Challenge Panel.

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16 This document is available from our website, see link below: www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020–25/proposal#step-64162

17 The additional indicative prices submitted on 28 June 2019 are available from our website, see link below: www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020–25/proposal#step-64162

18 NER, cl. 6.10.3(b).

19 For more information on this issue, refer to our website, see link below: www.aer.gov.au/system/files/QFFper cent20-20Submissionper cent20onper cent20Ergonper cent20Energyper cent27sper cent20Regulatoryper cent20Proposalper cent202020–25per cent20-per cent2031per cent20Mayper cent202019.pdf

18.2 Ergon Energy's proposal

For the purposes of this draft decision, we are assessing the 14 June 2019 version of its proposed tariff structure statement.[20]

The key elements of Ergon Energy's tariff reform proposal for the 2020–25 regulatory control period are summarised below:

- To introduce the following new tariffs from 1 July 2020:
    - Default demand tariffs for new customers.[21]
    - Opt-in capacity tariffs.[22]
    - Inclining block tariffs for existing customers.[23]
    - Controlled load tariffs for business customers.[24]
    - Opt-in TOU energy tariffs for customers on a retail transitional tariff.[25]
- To undertake the following tariff assignments and re-assignments:
    - Re-assign all existing residential and small business customers to a new inclining block tariff on 1 July 2020, including existing customers with smart metering installed in their premise.[26]
    - Re-assign all existing residential and small business customers to the applicable default demand tariff that change their metering arrangements from 1 July 2020.[27]
    - Assign all new residential and small business to a default demand tariff from 1 July 2020.[28]

Ergon Energy also proposes to allow certain customers to opt-out of cost reflective tariffs in in the 2020–25 regulatory control period, as summarised below:

- Allow hardship customers to opt-in to the legacy flat tariff from 1 July 2020.[29]
- Allow customers assigned to a transitional retail tariff in the current regulatory control period to opt-in to a network TOU energy tariff from 1 July 2020.[30]

[20] The updated tariff structure statement is available from our website, see link below: www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020–25/proposal#step-64162

[21] Ergon Energy, *2020–25 TSS Explanatory Notes*, June 2019, p. 21.

[22] Ergon Energy, *2020–25 TSS Explanatory Notes*, June 2019, p. 21.

[23] Ergon Energy, *2020–25 TSS Explanatory Notes*, June 2019, p. 21.

[24] Ergon Energy, *2020–25 TSS Explanatory Notes*, June 2019, p. 22.

[25] Ergon Energy, *2020–25 Tariff Structure Statement*, June 2019, p. 14.

[26] Ergon Energy, *2020–25 Tariff Structure Statement*, June 2019, table 3, p. 18.

[27] Ergon Energy, *2020–25 Tariff Structure Statement*, June 2019, p.13.

[28] Ergon Energy, *2020–25 Tariff Structure Statement*, June 2019, Table 3, p. 18.

[29] Ergon Energy, *2020–25 Tariff Structure Statement*, June 2019, p. 13.

[30] Ergon Energy, *2020–25 Tariff Structure Statement*, June 2019, p. 14.

18.3 AER draft decision

Our draft decision is to not approve Ergon Energy's proposed tariff structure statement, as we are not satisfied that it complies with the distribution pricing principles in the Rules.[31]

Although we are satisfied that parts of tariff structure statement contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective, we consider that some elements of the tariff structure statement require amendment and further detail and therefore the statement cannot be approved as a whole.

We consider the following elements of Ergon Energy's tariff structure statement contribute to compliance with the distribution pricing principles:[32]

- Proposed adoption of a more cost reflective tariff as the default tariff for residential and small business customers, although as discussed below we consider that the specific design of the default tariff must be changed to achieve compliance with the distribution pricing principles in the Rules.
- Proposed introduction of new controlled load tariffs for business customers connected at the low voltage level of the electricity distribution network.[33]
- Proposed opt-in time of use tariff for customers on transitional retail tariffs.[34]
- Proposed removal of excess kVAr charges. [35]
- We accept that the proposed method for estimating long run marginal cost satisfies the distribution pricing principles in the Rules.[36]

However, our draft decision is to not accept the other key elements of Ergon Energy's tariff structure statement.

Each of the elements listed below requires further work in order to achieve compliance with the distribution pricing principles in the Rules:[37]

- Ergon Energy has not demonstrated that the proposed price level of its peak charging parameters for the existing and new cost reflective tariffs comply with the distribution

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31 NER, cll. 6.18.5(b) and (d).

32 NER, cl. 6.18.5 (a).

33 It should be noted that we require the Queensland distributors to provide greater transparency in their revised tariff structure statement in regard to the eligibility criteria for these tariffs to achieve full compliance with the distribution pricing principles in the Rules.

34 It should be noted that we consider that Ergon Energy should introduce a time of use energy tariff to be made available to all customers with smart metering on an opt-in basis.

35 Ergon Energy*, 2020–25 Tariff Structure Statement - explanatory note*, June 2019, p. 18.

36 It should be noted that we require Ergon Energy to transition its demand charges for all customers to long run marginal cost over a reasonable timeframe in recognition of its network circumstances of significant excess capacity and minimal growth in peak demand;

37 NER, cl. 6.18.5(d).

pricing principles in the Rules. Ergon Energy has proposed high estimates for Long Run Marginal Cost (LRMC). However, given the level of excess capacity on its network and the prospect of minimal growth in peak demand in the foreseeable future, we consider low LRMC estimates to be more appropriate for its network circumstances;

- Ergon Energy has not demonstrated that its proposed structure of the inclining block tariffs, demand tariffs and capacity tariffs comply with the distribution pricing principles in the Rules;
- Ergon Energy has not demonstrated that its proposal to allow existing customers with smart metering to remain assigned to a non-cost reflective tariff complies with the distribution pricing principles in the Rules;
- Ergon Energy has not demonstrated that its proposal to allow hardship customers to opt-in to the legacy flat tariff complies with the distribution pricing principles in the Rules. Ergon Energy has not demonstrated that customers assigned to a demand tariff would be worse off than if those customers are assigned to the legacy tariff;
- Ergon Energy has not demonstrated that its TSS proposals comply with the customer impact principle in the rules due to the inadequacy of its customer impact analysis; and
- Due to insufficient information, there are some elements of the updated tariff structure statement that we are unable to assess, in terms of the NER principles and objectives, such as the proposed introduction of kVA-based demand tariffs for large customers and the re-assignment of customers with relatively high cost to serve to individually calculated tariffs.

We also encourage the Queensland distributors to provide greater clarity in their revised tariff structure statement on the underlying rationale for their tariff reform proposals, particularly in the context of the future challenges arising from the increasing penetration of solar PV, electric vehicles, batteries. This clarity will assist us to assess the tariff reform proposal from the perspective of meeting the NER pricing principles and objectives. We also observe from the submissions that we received from stakeholders that they will benefit from having a better understanding of the underlying rationale for tariff reform.[38]

The following table provides a summary of the key elements of Ergon Energy's tariff strategy that we have not accepted on the basis of the information set out in the updated tariff structure statement. The information to date does not support these elements as contributing to meeting the distribution pricing principles and to the achievement of the network pricing objective. We require that Ergon Energy make changes to the elements noted in Table 18.1. We have provided guidance to the Queensland distributors on how our concerns may be addressed. For elements of the proposal that we support in principle, we require Ergon Energy to provide additional clarity and to undertake additional analysis in their revised tariff structure statement in order to meet the distribution pricing principles in the Rules.

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[38] Energy Consumers Australia, *Energy Queensland Tariff Structure Statements 2020–25*, Submission, June 2019, p. 22.

Table 18.1 Summary of the key elements of our draft decision

Proposal	Compliance Assessment	Guidance
Inclining Block Tariff	Not approve	• Adopt flat tariff for residential customers • Adopt flat tariff or re-designed IBT for small business customers based on Endeavour Energy approach
Demand Tariff – residential and small business	Not approve	• Remove the day-time demand charging parameter. • Transition the price level of the demand charging parameter to LRMC over time. • To apply the proposed 12 month grace period to existing customers with a smart meter as at 30 June 2020. • Provide these customers with the choice of an opt-in TOU energy tariff.
Capacity Tariff – residential and small business	Not approve	• Work with stakeholders to undertake a capacity tariff trial in the 2020–25 regulatory control period. • Use the learnings and empirical evidence from this trial to design a new capacity tariff proposal for introduction in the 2025-30 regulatory control period.
Controlled load tariff	In-principle support	• Work with stakeholders to provide an understanding of the bill savings associated with taking up control load tariffs. • Provide greater clarification over the eligibility criteria associated with these tariffs.
Opt-in TOU tariff for customers on transitional retail tariffs	In-principle support	• Provide clarity over the transition path to cost reflectivity for these customers. • Re-assess the need for this mitigation measure once the design of the transitional demand tariff has been finalised.

Proposal	Compliance Assessment	Guidance
Allow hardship customers to opt-in to legacy flat tariff	Not approve	• Close the flat tariff to any additional customers (i.e. do not allow opt-in). • Introduce a simple TOU energy tariff that is designed to be as cost reflective as the transitional demand tariff. • Allow all customers on the demand tariff to opt-in to the TOU energy tariff if they choose.
Introduction of kVA demand pricing for large business customers	In-principle support	• Provide greater clarity over this proposal, particularly in terms of the customer impacts associated with this proposal • Clearly demonstrate that these impacts satisfy the customer impact principle in the Rules, if not engage stakeholders on effective mitigation options.
Individually calculated site-specific tariffs	In-principle support	• Provide more detailed information on the proposed price-setting approach for these customers, particularly in terms of the allocation of residual costs. • Provide more detailed information and justification of the proposed eligibility criteria for assigning and re-assigning customers to these more bespoke network tariffs.

Source: AER analysis.

We encourage Ergon Energy to use the time before the submission of its revised tariff structure statement to consult with stakeholders and the AER on how it intends to respond to the issues and concerns raised in this draft decision, such as whether it proposes to revise its proposal in relation to:

- The structure of existing and new tariffs, and the rationale for these changes in the context of the distribution pricing principles.
- The introduction of new tariffs, and the rationale for these changes from a compliance perspective.
- The approach to setting the price levels of tariffs to signal long run marginal costs and allocate residual costs, as reflected in indicative pricing schedule, and the rationale for these changes from a compliance perspective.

We also consider that it is important the Queensland distributors engage with stakeholders and the AER on how it proposes to address the information gaps that we have identified in this draft decision.

As a matter of administrative simplicity, we encourage the Queensland distributors to adopt the two-document structure for their revised tariff structure statement, which is due to be submitted to the AER in December 2019. This structure is similar to the tariff structure statements of other distributors, such as Endeavour Energy.[39] The first document must be limited to the content that will bind Ergon Energy over the regulatory control period and the second document explains Ergon Energy's reasons for its binding positions. This will improve clarity of the tariff structure statement for retailers, customers and the AER. We have encouraged all distributors to adopt this approach.

18.4 AER's assessment approach

This section outlines our approach to tariff structure statement assessments.

There are two sets of requirements for tariff structure statements. First, the NER set out a number of elements that an approved tariff structure statement must contain.[40] Second, a tariff structure statement must also comply with the distribution pricing principles.[41]

What must a tariff structure statement contain?

The Rules require a tariff structure statement to include:[42]

- 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, and
- a description of the approach that the distributor will take in setting the price level of their tariffs in the pricing proposal for each regulatory year during the 2020–25 regulatory control period.

A distributor's tariff structure statement must be accompanied by an indicative pricing schedule with the tariff structure statement.[43] This schedule guides stakeholder expectations about annual changes in the price level of network tariffs over the 2020–25 regulatory control period. As a result, we require that the annual prices in the indicative pricing schedule be

39 Endeavour Energy, *Tariff Structure Statement - 2019-24 Regulatory control period*, January 2019.

40 NER, cl. 6.18.1A(a).

41 NER, cl. 6.18.1A(b).

42 NER, cl. 6.18.1A(a).

43 NER, cl. 6.18.1A (e).

based on the proposed methodologies in the tariff structure statement for signalling long run marginal costs and the efficient recovery of residual costs.

What must a tariff structure statement comply with?

A tariff structure statement must comply with the distribution pricing principles for direct standard control services.[44] These 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.[45]
- each tariff must be based on the long run marginal cost of serving those customers, with the method of calculation and its application determined with regard to the costs and benefits of that method, the costs of meeting demand from those customers at peak network utilisation times, and customer location.[46]
- 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.[47]
- distributors must consider the impact on customers of tariff changes and may depart from efficient tariffs, if reasonably necessary having regard to:[48]
    - 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.
- tariff structures must be reasonably capable of being understood by retail customers assigned to that tariff.[49]
- tariffs must otherwise comply with the Rules and all applicable regulatory requirements.[50]

The tariff structure statement must comply with the distribution pricing principles in a manner that will contribute to the achievement of the *network pricing objective*:[51]

> *The network pricing objective is that the tariffs that a DNSP charges in respect of its provision of direct control services should reflect the DNSP's efficient costs of providing those services to the retail customer.*[52]

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44 NER, cl. 6.18.1A(b).
45 NER, cl. 6.18.5(e).
46 NER, cl. 6.18.5(f).
47 NER, cl. 6.18.5(g).
48 NER, cl. 6.18.5(h).
49 NER, cl. 6.18.5(i).
50 NER, cl. 6.18.5(j); this requirement includes jurisdictional requirements.
51 NER, cl. 6.18.5(d).

Role of the Tariff Structure Statement

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

This included splitting the network pricing process into two stages.

Table 18.2 Two stage network pricing process

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

Source: AER.

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

- requirements that would facilitate meaningful consultation and dialogue between distributors, the AER, retailers and consumers.
- increased certainty with respect to changes in network tariff structures and more timely notification of approved changes to network tariff pricing levels.
- more opportunity for retailers and consumers to inform and educate themselves about how network tariffs will affect them and how they should respond to the pricing signals.

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

- the AER to have appropriate timeframes and capacity to assess the compliance of the distributors proposed network tariffs against the distribution pricing principles and other requirements.
- distributors to maintain ownership of network tariffs and to adjust the pricing levels of their tariffs to recover allowed revenues.[53]

What happens after a tariff structure is approved?

Once approved, a tariff structure statement will remain in effect for the relevant regulatory control period. The distributor must comply with the approved tariff structure statement and be consistent with the indicative pricing schedule[54] when setting prices annually for direct control services.[55]

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

An approved tariff structure statement may only be amended within a regulatory control period with our approval.[56] We will approve an amendment if the distributor demonstrates that an event has occurred that was beyond its control and which it could not have foreseen, and that the occurrence of the event means that the amended tariff structure statement materially better complies with the distribution pricing principles.[57]

18.5 Reasons for draft decision

Our draft decision is to not approve Ergon Energy's proposed tariff structure statement, as we are not satisfied that it complies with the distribution pricing principles in the Rules or contributes to the achievement of the network pricing objective.[58]

Although we are satisfied that parts of tariff structure statement contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective, we consider that some elements of the tariff structure statement require amendment and further detail.

We outline below our draft decision on each element of Ergon Energy's proposed tariff structure statement. We have also included a series of appendices which support these reasons.

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

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

55 NER, cl. 6.18.1A(c).

56 NER, cl. 6.18.1B.

57 NER, cl. 6.18.1B(d).

58 NER, cll. 6.18.5(b) and (d).

This section of our draft decision is structured to provide our detailed assessment of whether the following elements of Ergon Energy's updated tariff structure comply with the distribution pricing principles in the Rules:

- Assessing the completeness of the proposal (i.e. does it include all the constitute elements of a tariff structure statement);
- Proposed grouping of customers into tariff classes;
- Proposed changes to tariff structures and the related assignment and reassignment procedures in the residential and small business customer segment;
- Proposed changes to tariff structures and the related assignment and reassignment procedures in the medium and large business customer segment; and
- Proposed methodologies for long run marginal cost and residual cost.

18.5.1 Statement structure and completeness

Ergon Energy must include the following elements within its tariff structure statement:

- the tariff classes into which its customers will be grouped
- the policies and procedures Ergon Energy will apply for assigning customers to tariffs or reassigning customers from one tariff to another (including applicable restrictions)
- the structures for each proposed tariff
- the charging parameters for each proposed tariff
- a description of the approach that Ergon Energy will take in setting each tariff in each annual pricing proposal during the regulatory control period.[59]

Ergon Energy must also accompany its proposed tariff structure statement with an indicative pricing schedule, which sets out, for each tariff for each regulatory year of the regulatory control period, the indicative price levels determined in accordance with the tariff structure statement.[60]

Ergon Energy's proposed tariff structure statement incorporates each of the elements required under the Rules. The key focus of our assessment for this draft decision is on whether these elements satisfy the distribution pricing principles in the Rules.

We note that Ergon Energy has included placeholder proposals in their tariff structure statement for the purpose of introducing the following new tariffs during the 2020–25 regulatory control period:

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

[60] NER, cl. 6.18.1A(e).

- A new capacity tariff for residential and small business customers with basic accumulation meter, subject to further engagement with stakeholders.[61]
- A public lighting metered supply tariff in the event of a future amendment to the metrology requirements set out in Chapter 7 of the Rules.[62]

We do not consider these proposals comply with the Rules given the inadequate information provided in tariff structure statement. We require that these elements be removed from the revised tariff structure statement. We note that there are provisions in the Rules for Ergon Energy to apply to the AER to have their tariff structure statement reopened during the course of the regulatory control period, if the limited circumstances under the tariff structure statement can be reopened are met.[63] Alternatively, Ergon Energy could introduce these tariffs on a trial basis. However, any tariff which is proposed for inclusion in the tariff structure statement must be fully specified in order for it to be considered. Proposing an unspecified placeholder tariff does not provide the certainty to stakeholders that the tariff structure statement is intended to achieve. It also provides insufficient information for the AER to properly assess the proposal against the distribution pricing principles.

We encourage the Ergon Energy to improve this document from a compliance perspective by more clearly describing the proposed tariff setting approach during the 2020–25 regulatory control period[64] by including the following information in the revised tariff structure statement:

- A clear statement of the problem that tariff is trying to address, noting the context of these reforms in regard to the on-going transformation of the energy sector due to the uptake of DER.
- A clear explanation of how the proposed tariff reforms are intended to address this problem.
- Inclusion of more robust and evidence based discussion on the customer impact of the proposed tariff reforms and the extent that customers are able to mitigate these impacts by switch to other primary tariffs or taking up controlled load tariffs, or even by responding to these price signals by changing their network usage behaviour
- Inclusion of more robust and evidence based discussion on the extent that the proposed tariff reforms comply with the efficiency principles in the Rules, including the requirement to recover residual costs in a least distortionary manner to efficient usage of the electricity network.
- A clear description of the basis of the annual prices shown in the indicative pricing schedule, particularly in regard to demonstrating that the indicative prices have been

61 ` Ergon Energy, *Tariff Structure Statement*, 14 June 2019, p. 28.

62 Ergon Energy, *Tariff Structure Statement*, 14 June 2019, p. 23.

63 NER, cl. 6.18.1B.

64 NER, cl. 6.18.1(a)(5).

developed on the basis of the proposed price-setting methodologies set out in the tariff structure statement.

- A clear description on how it will vary tariffs from the indicative pricing schedule if the inputs to the price-setting process during the 2020–25 regulatory control period vary from the assumptions underpinning the indicative prices set out in the indicative pricing schedule accompanying the revised tariff structure statement.[65]

We recognise that Ergon Energy has adopted our preferred "two document" approach:

- the first document should include only include the aspects of the tariff structure statement that will bind Ergon Energy over the reset period.
- the second document should explain Ergon Energy's reasons for what it has proposed.

This approach improves the clarity for the retailers, customers and AER.[66]

18.5.2 Proposed tariff classes

A tariff class is a class of customers for one or more direct control services who are subject to a particular tariff or particular tariffs.[67] A tariff class must be constituted with regard to the need to group retail customers together on an economically efficient basis, and the need to avoid unnecessary transaction costs.[68]

Ergon Energy proposes to rationalise the number of tariff classes for standard control services from 16 to 7 tariff classes for the 2020–25 regulatory control period by adopting a tariff class structure that aligns with the voltage level of the customer's connection to the electricity distribution network.[69] We approve this element of Ergon Energy's proposal.

Ergon Energy proposes the following standard control service tariff classes:

- Separate standard asset customer (SAC) tariff classes for its East, West and Mount Isa regions. SAC tariff class customers are typically connected to the low voltage (LV) network.
- Separate connection asset customer (CAC) tariff classes for its East, West and Mount Isa regions. CAC tariff class customers are connected to either the high voltage (HV) (11kV, 22kV) network or the lower voltages of the sub-transmission network (33kV, 66kV).

65 Inputs to the price-setting process include the closing balance of the overs and unders account, customer numbers and volumes by charging parameter

66 NER, cl. 6.18.5(i).

67 NER, chapter 10 glossary.

68 NER, cl. 6.18.3(d).

69 Ergon Energy, *Tariff structure statement explanatory notes*, June 2019, p.19.

- A single tariff class for its individually calculated customers (ICC). ICC tariff class customers are connected to either the higher end of the HV network (66kV) or the sub-transmission network (33kV, 66kV, 110kV).

Ergon Energy proposes to achieve this rationalisation by eliminating some tariff classes and reassigning those customers to other tariff tariffs or by merging some tariff classes.[70]

We are satisfied that Ergon Energy's proposed rationalisation of tariff classes for the 2020–25 regulatory control period is economically efficient and avoids unnecessary transaction costs.[71] This is because:

- Ergon Energy's current tariff classes are complex compared to other distributors in the national electricity market (NEM), particularly given their regional distinctions—Ergon Energy's proposed changes will result in customers being grouped in a similar manner to other electricity distributors in the NEM, as discussed in Appendix A.
- The proposed rationalisation of tariff classes may reduce transaction costs.
- Our understanding is that the proposed rationalisation of tariff classes will have no detrimental impact on customers given that it will not result in affected customers being reassigned to another network tariff.

Our only concern is the inadequate and unclear information on the proposed eligibility criteria of the individually calculated tariff class.[72] For example, the TSS explanatory note clearly states that ICC tariff class is restricted to customers coupled to the electricity distribution network at higher voltage levels i.e. 22kV, 33kV, 66kV 100kV.[73] Whereas the tariff structure statement could be interpreted to allow customers coupled at the low voltage level of the electricity distribution network to be assigned or reassigned to the ICC tariff class if they satisfy the alternative criteria, such as where the nature of the connection and/or usage of the network makes the application of published tariffs inappropriate.[74]

To comply with the distribution pricing principles in the Rules we require more clarity on this aspect of the tariff class proposal. We consider that this issue could be achieved by addressed by providing the following information in their revised tariff structure statement:

- Specific examples of a dedicated distribution system that are sufficiently[75] different and separate from the remainder of the electricity distribution system to satisfy the eligibility

[70] Specially, Ergon Energy proposed to eliminate unmetered tariff class and re-assign these customers to an appropriate proposed tariff class; to eliminate the embedded generation tariff class and reassign these customers to an appropriate proposed tariff class; and to merge the existing small and large standard access customer tariff classes.

[71] NER, cl. 6.18.3(d).

[72] Ergon Energy, *Tariff Structure Statement 2020–25*, Table 2, June 2019, p. 16.

[73] Ergon Energy, *Tariff Structure Statement 2020–25 Explanatory Note*, June 2019, p. 19.

[74] Ergon Energy, *Tariff Structure Statement 2020–25*, June 2019, p. 16.

[75] This threshold should be explicitly defined in the revised tariff structure statement.

criteria of the ICC tariff class even though they have an installed capacity of less than 10 MVA.

- Specific examples of customers that due to the nature of the customer's connection and/or usage of the network is sufficiently[76] different for other customers to satisfy the eligibility criteria of the ICC tariff class even though they have an installed capacity of less than 10 MVA.
- Specific examples of customers that due to their proximity[77] to a transmission connection point satisfy the eligibility criteria of the ICC tariff class even though they have an installed capacity of less than 10 MVA.
- Specific examples of customers that due to equity[78] concerns satisfy the eligibility criteria of the ICC tariff class even though they have an installed capacity of less than 10 MVA.

We note that the Queensland distributors must satisfy the requirements set out in Appendix D of this attachment when assigning or reassigning customers to tariff classes. In this regard we consider that existing and new customers should only be assigned or re-assigned to the ICC tariff class as part of the annual price reset process.[79] In this way, the customer will be assigned or reassigned to a site-specific network tariff that is approved by the AER.

18.5.3 Proposed tariffs for residential and small business customers

This section of our draft decision provides our assessment of Ergon Energy's proposed tariff reforms for its residential and small business customers[80] in the 2020–25 regulatory control period.

The sections below set out our position on the following specific reform proposals in the residential and small business customer segment:

- The proposed introduction of an inclining block tariff on 1 July 2020.
- The proposed re-assignment of existing customers on existing legacy tariffs and cost reflective tariffs on 1 July 2020.
- The proposed introduction of a default demand tariff for all new customers and existing customers that install a smart meter after 30 June 2020.
- The proposed introduction of a capacity tariff on an opt-in basis.

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76 This threshold should be explicitly defined in the revised tariff structure statement.

77 This term should be explicitly defined in the revised tariff structure statement.

78 This term should be explicitly defined in the revised tariff structure statement.

79 As opposed to being assigned or reassigned to a tariff during the course of the financial year that has not been approved by the AER as part of the compliance assessment process for the 1 July pricing proposal.

80 A small business customer is defined as a business customer connected to the low voltage level of electricity distribution network that consumes less than 100 MWh per annum.

- The proposed introduction of new controlled load tariffs on an opt-in basis.
- The proposed mitigation measures, such as the introduction of ToU tariff for customers on a transitional retail tariff and allowing customers on a retail hardship program to opt-in to existing legacy tariffs.

It is important to note that we have also drawn on our recent TSS decisions in other jurisdictions (and included as Appendix B of this decision) to provide guidance to Ergon Energy on how they can improve their tariff structure statement by:

- Providing customers with a choice of cost reflective tariff structures by also introducing an opt-in time of use energy tariff.
- Ensuring that most customers benefit from cost reflective pricing by setting the cost reflective tariff at an inherent discount to the legacy tariffs.
- Delaying the reassignment of customers from the flat tariff to the cost reflective tariff by up to 12 months to provide adequate time for customers, retailers and the Queensland distributors to prepare for this major change in tariff structure.

All customers with smart meters should face cost reflective tariffs

The key elements of Ergon Energy's proposed procedure for assigning or reassigning residential and small business customers to a tariff is summarised in the table below.

Table 18.3 Ergon Energy's proposed default tariff arrangements for residential and small business customers

Residential and small business customers	Proposed default network tariff	Description
Existing customers with basic accumulation metering	Inclining block	Reassign to new inclining block tariff structure introduced on 1 July 2020. These customers are allowed to opt-in to a more cost reflective tariff if they upgrade their metering.
Existing customers with smart metering as at 30 June 2020	Inclining block	Reassign to a new inclining block tariff structure introduced on 1 July 2020. These customers are allowed to opt-in to the more cost reflective tariff.
New customers that connect to the electricity distribution network from 1 July 2020[81]	Demand	Assigned by default to a demand tariff. These customers are allowed to opt-in to the capacity tariff.

81 Under the metering rules all new customers are required to have a smart meter

Residential and small business customers	Proposed default network tariff	Description
Existing customers that have their basic accumulation meter replaced due to end of life replacement from 1 July 2020	Demand	Assigned by default to a demand tariff. These customers will be given a 12 month sampling period[82] and are allowed to opt-in to the capacity tariff.
Existing customers that upgrade to a smart meter due to a change in their connection characteristic (e.g. Solar PV or upgrade to 3 phase) from 1 July 2020	Demand	Assigned by default to a demand tariff. These customers are allowed to opt-in to the capacity tariff.

Source: Ergon Energy.

We agree with Ergon Energy's proposal to assign new customers by default to a demand tariff (though we disagree with the specific design of the proposed demand tariff which we analyse in the next section). We also agree with Ergon Energy's proposal to assign existing customers who receive a smart meter after 1 July 2020 by default to a demand tariff. We consider this element of Ergon Energy's proposal contributes to the achievement of the distribution pricing principles given that it will result in an increase in the number of customers on cost reflective network tariffs over time. In Appendix B we explain why we consider it's appropriate to assign new customers and existing customers who receive a smart meter by default to a cost reflective network tariff.

However, we disagree with Ergon Energy's proposal:

- To not assign existing customers who already have a smart meter to a cost reflective network tariff, and instead assign these customers to the proposed inclining block tariff.[83]
- To retire the existing seasonal time-of-use energy and seasonal demand tariffs, and re-assign customers currently on those tariffs to the somewhat less cost reflective non-seasonal demand tariff.

We are not satisfied that these elements of Ergon Energy's proposal comply with the pricing principles in the Rules.

We note that there is expected to be a significant number of residential and small business customers with smart metering who will be assigned to a non-cost reflective legacy tariff in

[82] Ergon Energy, *Tariff Structure Statement*, June 2019, p. 13.

[83] Ergon Energy's current legacy tariff is an inclining block tariff. For more information, refer to Ergon Energy's pricing proposal. This document is available: www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/ergon-energy-annual-pricing-2019-20

Queensland at the start of the 2020–25 regulatory control period.[84] We understand that under Ergon Energy's proposal, these customers will only be re-assigned to a more cost reflective tariff in the 2020–25 regulatory control period under the following circumstances:

- When the retailer replaces their customer's existing meter when it reaches the end of its technical life.
- The retailer applies on behalf of their customer to change their connection characteristic (e.g. upgrades to a three phase connection) and requires a new smart meter to be installed.
- The retailer applies on behalf of their customer to voluntarily be reassigned to a more cost reflective network tariff.

We are concerned that this proposal will result in many of these customers remaining on the inclining block tariff for many years given that all have relatively new metering installed and that a significant proportion of these customers are likely to have already installed a solar PV system given the significant take-up of DER in recent years, as evident from Appendix A.

To address our compliance concerns, we require that these customers be reassigned to the applicable demand tariff in the 2020–25 regulatory control period. We consider that reassigning these customers to a cost reflective tariff is likely to result in these customers receiving more efficient price signals in regard to their peak usage[85] and will contribute to residual costs being recovered in a less distortionary manner.[86]

While we acknowledge that re-assigning these customers to a more cost reflective tariff presents both opportunities and challenges, we consider the risks can be effectively managed if Ergon Energy undertakes these tariff reassignments in a manner that does not contravene the customer impact principle in the Rules. We consider that this outcome can be achieved if the following safeguards are put in place:

- The design of the demand tariff structure is reasonably capable of being understood by customers, such as by simplifying the tariff structure by removing the day-time demand charging parameter.[87]
- The default demand tariff should be set at an inherent discount to the applicable legacy tariff to ensure that most customers benefit from the introduction of cost reflective pricing.
- The distributor delays reassigning existing customers with a smart meter to a demand tariff by 12 months.[88] This grace period will provide these customers (and their retailer) with adequate time to:

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84 We understand that around 15 per cent of Ergon Energy's residential and small business customers will have a smart meter installed as at 30 June 2020, as discussed in Appendix A

85 NER, cl. 6.18.5(f).

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

87 NER, cl. 6.18.5(h).

- understand the more complex cost reflective tariff structure,
- investigate how to mitigate the bill impact under the demand tariff, including the extent that they may can change their behaviour in response to demand charges, or invest in more energy appliances and energy technology such as solar PV systems and batteries.[89]

- Peak demand charge under the demand tariff is set initially at a low price level and transitioned to long run marginal cost over a reasonable timeframe. We consider that having low demand charges in an environment of excess capacity is likely to result in minimal, if any, loss in economic efficiency.
- Customers have the opportunity to opt-in to an alternative cost reflective tariff e.g. time of use energy tariff, if they find that the demand tariff is too complex. We support giving customers the choice of cost reflective tariff structure to the extent that allowing customers to do so makes progress towards greater cost reflectivity without imposing unacceptable impacts on customers.[90]

It is also our understanding that these customers will also receive support under Ergon Energy's proposed Tariff Education Dynamic Incentive (TEDI) framework.[91] We envisage that this will ensure that these customers have access to the information necessary for them to make informed tariff choices and decisions about upgrading their appliance mix, investing in solar PV and other DER, and how best to sustainably modify their electricity usage to fully benefit from the incentives under the more cost reflective demand tariff structure.[92]

We also note that Ergon Energy proposes to either retire or grandfather their existing seasonal time of use energy tariff[93] and seasonal time-of-use demand tariff[94] in the 2020–25 regulatory control period. Under this proposal, no new customers will be allowed to opt-in to these tariffs and the existing customers on these tariffs will be reassigned to the applicable default demand tariff on 1 July 2020. On the basis of the information in the updated tariff structure statement, we are not convinced that this proposal complies with the Rules,

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88 Note that we are not opposed to customers opting in to the cost reflective tariff during this 12 month grace period given that there may be opportunities for customers to pay less under the cost reflective tariff, particularly if they are willing to respond to these price signals by reducing their peak demand.

89 The grace period is also required to provide adequate time for customers to make informed tariff choices i.e. whether to take up a controlled load tariff if they are willing to accept supply interruptions.

90 AER, Attachment 18 - *Tariff Structure Statement - Draft Decision - Ausgrid Distribution Determination*, November 2018, pp. 18-22.

91 Energy Queensland, *Response to AER information request, item 7*, 8 July 2019, p. 16.

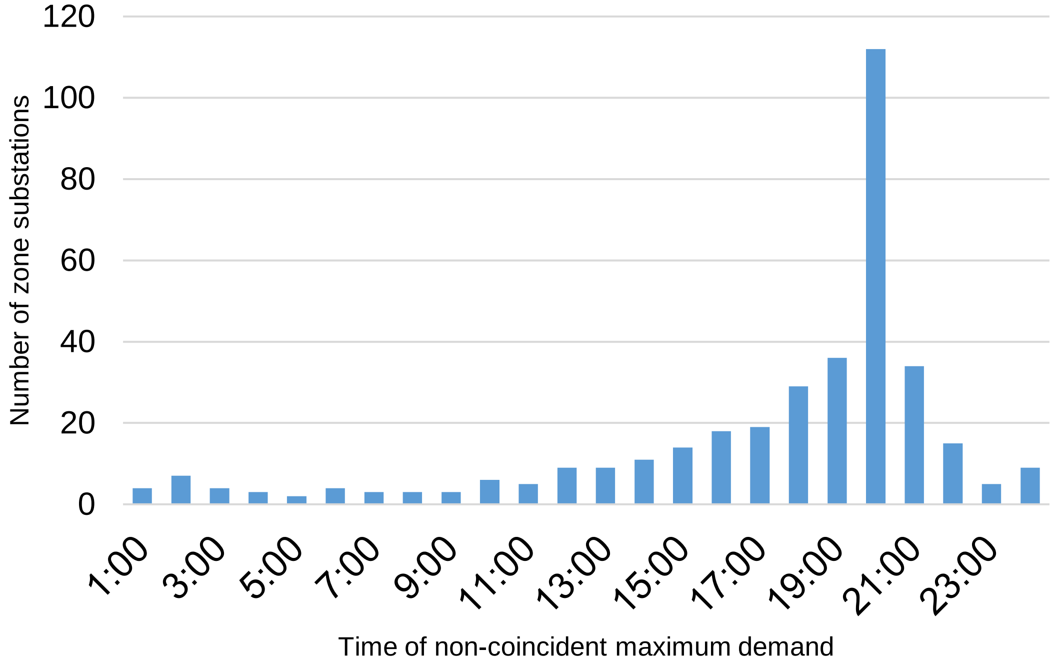
92 This assumes that Retailers decide to pass through the cost reflective network tariff structure to end-customers.

93 The legacy seasonal ToU tariff is based on a summer peak charging window of 3pm to 9.30pm every day during the summer months of December, January and February. This structure is reflected in regulated retail tariff 12A for residential customers and Tariff 22A for small business customers.

94 The legacy seasonal ToU demand tariff is based on a summer peak charging window of 3pm to 9.30pm every day during the summer months of December, January and February. This structure is reflected in regulated retail tariff 14 for residential customers and Tariff 24 for small business customers.

particularly given that these tariffs better reflect the seasonal pattern of peak demand in Ergon Energy's network, as highlighted in the figure below.

Figure 18.1 Zone substation peaks by time of day – Ergon Energy



Source: AER analysis.

To address our concerns Ergon Energy should not reassign existing customers on these tariffs to the applicable default demand tariff. We also consider it appropriate for the existing seasonal time-of-use energy and demand tariffs to be available on an opt-in basis to all customers with smart metering.

We encourage Ergon Energy to work constructively with its stakeholders to ensure that its revised tariff structure statement addresses our concerns in regard to this element of their tariff reform agenda.

The structure of the default demand tariff must be improved

Ergon Energy proposes to adopt a demand tariff as its default tariff for new residential and small business customers and existing customers that install a smart meter after 30 June 2020.[95] Ergon Energy also proposes to re-assign existing customers currently on a seasonal

[95] Note that Ergon Energy refers to these default tariffs in its tariff structure statement as the Residential Demand Tariff and Business Demand tariff.

time-of-use demand tariff to these new demand tariffs, and retailers can opt-in other existing customers with smart meters to these new demand tariffs.[96]

Ergon Energy's proposed tariff structure for its Residential Demand tariff is shown in the table below. Ergon Energy also proposes to adopt a similar structure for its Business Demand tariff. Both tariffs have a daytime maximum demand charging window of 10am to 4pm and an evening maximum demand charging window of 4pm to 9pm. However, the Business Demand tariff applies those demand charging windows on weekdays (excluding public holidays), whereas the Residential Demand tariff applies those demand charging windows on every day of the year.[97]

We agree with Ergon Energy's proposal to apply demand tariffs as the default tariff for new residential and small business customers and existing customers who install a smart meter. However, we do not agree with the specific design of Ergon Energy's demand tariffs or the way Ergon Energy has reflected its LRMC estimates in these tariffs. That is the focus of our assessment in this section. We also consider a default demand tariff should be applied to existing customers with smart meters, which we discuss in section 18.5.3.

Table 18.4 Ergon Energy's proposed default demand tariff structure for residential customers

Charging parameter	Unit	Description of charging parameter
Fixed charge	c/day	This is a daily charge that is applied on a $ per day basis to each energised connection point, regardless of the level of usage.
Flat energy charge	c/kWh	This charge is applied on a cents per KWh basis for the total energy consumption recorded under this tariff during the billing period.
Daytime maximum demand charge	c/kW/m	This is a monthly charge that is applied on a $ per kilowatt (kW) for the maximum kW demand recorded during the day time peak charging window between 10am to 4pm every day.
Evening time maximum demand charge	c/kW/m	This is a monthly charge that is applied on a $ per kilowatt (kW) for the maximum kW demand recorded during the evening time charging window between 4pm to 9pm every day

Source: Ergon Energy.

Ergon Energy proposes to use the peak demand charging parameter as the basis to signal long run marginal cost. We are supportive of this general approach given that peak demand

96 Ergon Energy, *Tariff structure statement 2020–25*, June 2019, pp. 18-20.

97 Ergon Energy, *Tariff structure statement 2020–25*, June 2019, pp. 26-27.

charges, if well designed, can be just as cost reflective as peak energy charges.[98] It is also consistent with our recent TSS decisions in other jurisdictions, where we have assessed the demand charge to be compliant under the pricing principles in the Rules.[99]

It is also relevant to note that we accept that it is appropriate for distributors to design their demand charging parameters to reflect their unique circumstances, even though it may result in a divergence in approaches across distributors, as discussed in Appendix B of this draft decision.

We are satisfied that the inclusion of a fixed charge, flat energy consumption charge and an evening peak demand charge in the proposed demand tariff structure contributes to compliance with the distribution pricing principles in the Rules.[100] However, on the basis of the information in Ergon Energy's proposal we are not convinced that the proposed inclusion of a day-time peak demand charging parameter contributes to compliance with the distribution pricing principles in the Rules.[101]

Our analysis of the available historical peak demand patterns at the zone substation level found that the highest peak demands in the residential customer segment occur in the summer months of the year and are confined to the evening period. This is consistent with the conclusions of a recent study for the Queensland distributors by the consultant Endgame Economics.[102] On the basis of similar analysis that we have undertaken, we are satisfied that the peak demand charge should apply only to the evening period, as shown in Figure 18.2 below.

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98 Refer to Appendix B of this draft decision for a discussion on the cost reflectivity of different tariff structures.

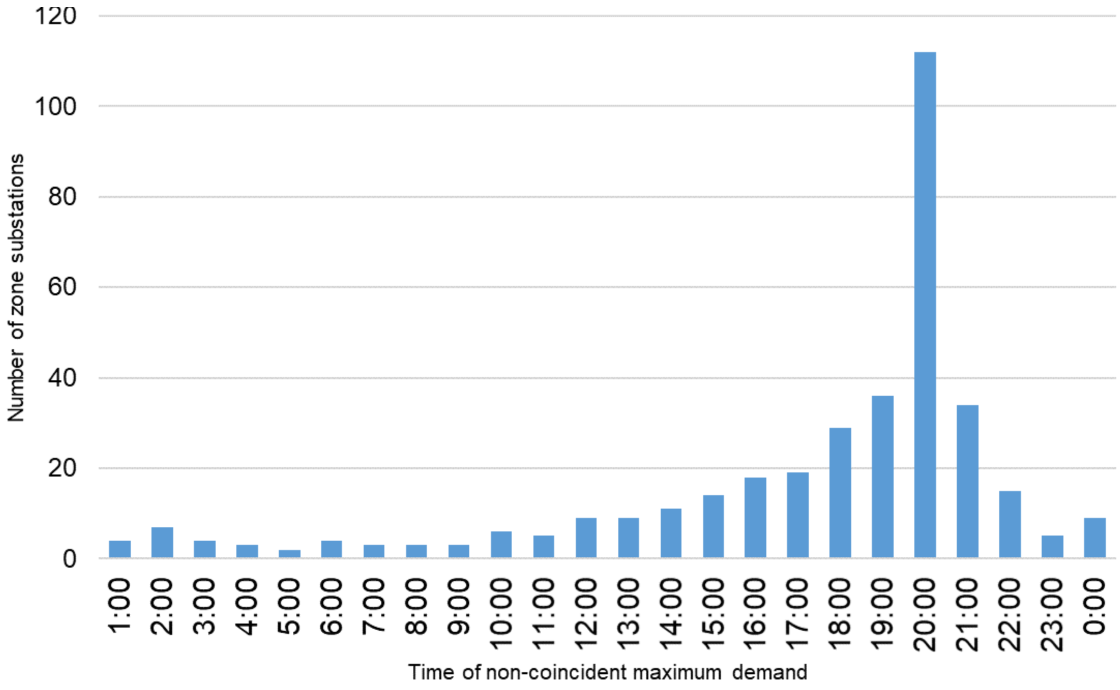
99 AER, *Attachment 18 - Tariff Structure Statement - Draft Decision - Ausgrid Distribution Determination*, November 2018, Appendix B.

100 We note that the peak charging windows only apply to small business customers on working days i.e. excluding public holidays and weekends.

101 NER, cll. 6.18.5(f) and 6.18.5(g).

102 Endgame Economics, *Analytics to inform Design and selection of tariffs* - Presentation to the QLD distributors, November 2017.

Figure 18.2 Zone substation peaks by time of day – Ergon Energy



Source: AER analysis.

While we accept the proposed evening time peak charging window is supported by the evidence that we have gathered, we require the Queensland distributors to set the price level under the evening demand charging parameter in a manner that is appropriate for its economic circumstances of excess capacity and minimal peak demand growth in the foreseeable future. We consider that compliance with the Rules can be achieved in this regard by setting the demand charge at a low price level in the first year of the 2020–25 regulatory control period and transitioning the level of the demand charge to LRMC over at least a ten year time frame.[103] This approach will result in minimal, if any, loss of economic welfare and has the considerable advantage of giving customers more time to become familiar with kW demand pricing without the risk of undermining support for tariff reform by imposing bill shocks on customers with peaky demand profiles. We note that approach has been successful in other jurisdictions.[104]

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103 The length of the transition period should be reviewed at the end of the 2020–25 regulatory control period to account for unanticipated developments in the peak demand environment.

104 AER, Attachment 18 - *Tariff Structure Statement - Final Decision - Endeavour Energy Distribution Determination*, April 2018, p. 12.

To achieve compliance with the pricing principles in the Rules, we encourage the Queensland distributors to engage with the stakeholders on the following revisions to their default demand tariff proposal for residential and small business customers:

- To set the initial price of the evening peak charge well below their estimate of LRMC.
- To work constructively with stakeholders to develop a reasonable transition path for the demand charge, noting that we recently approved a 10 year transition to LRMC for Endeavour Energy.[105]
- To remove the day time demand charge.

We encourage Ergon Energy to work constructively with its stakeholders to ensure that its revised tariff structure statement addresses our concerns in regard to this element of their tariff reform agenda.

Inclining block tariff proposal is complex and not well supported by evidence

Ergon Energy proposes to introduce new inclining block tariffs for residential and small business customers.[106] Ergon Energy proposes to re-assign customers on its existing legacy inclining block tariffs to the new inclining block tariffs on 1 July 2020. Both existing customers with basic accumulation meters and those with smart meters (who are not currently assigned to a demand tariff) are proposed to be reassigned to this new tariff.[107] We do not agree with the introduction of these new tariffs or the proposed re-assignment policy for these customers.

Ergon Energy has not clearly explained the underlying rationale for this proposal in their tariff structure statement. To address this issue, we requested Ergon Energy explain what it is trying to achieve with the inclining block structure. In response to our information request, Ergon Energy stated it considers the inclining block structure:

- is more cost reflective as Ergon Energy is using energy consumption as a proxy for a customer using more capacity and therefore creating a higher cost to serve the customer, and
- it acts as a transitionary mechanism to minimise the impact on customers being re-assigned to capacity based network tariffs in the future (in accordance with Ergon Energy's long term tariff strategy) after the customer's meter is upgraded to a smart meter.[108]

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105 AER, *Attachment 18 – Tariff structure statement - FInal decision - Endeavour Energy distribution determination 2019–24*, April 2019, p. 14.

106 These proposed tariffs are referred to as its Residential Basic Tariff and Business Basic tariff in the tariff structure statement.

107 Ergon Energy, *Tariff structure statement 2020–25*, June 2019, pp.18-19.

108 Energy Queensland, *response to AER information request - item 4*, 8 July 2019, pp. 13-15.

We are not satisfied Ergon Energy's proposed inclining block tariff contributes to compliance with the distribution pricing principles in the Rules. This is because:

- Ergon Energy's proposal assumes there is a link between customer's total consumption and the level of capacity demanded by those customers during times of congestion. Ergon Energy has asserted this link rather than providing evidence to demonstrate it. Therefore, without supporting evidence, Ergon Energy has not demonstrated the inclining block tariff structure is cost reflective or would minimise the impact on customers being re-assigned to a capacity-based tariff in the future.[109]
- For Ergon Energy's existing residential and small business customers who already have smart meters there is no need to use a proxy for their level of demand. This is because these customers can be re-assigned to a demand-based tariff where the customer's level of demand during peak times can be measured directly—we discuss this issue further in Section 18.5.3 of this draft decision.
- Ergon Energy's proposed inclining block tariff structure is complex and therefore may be difficult for customers to understand.[110] For example, Ergon Energy proposes to substantially increase the number of consumption levels compared to its current inclining block tariff (see table below). This network structure is also likely to cause confusion among customers because it is not reflected at the retail level.[111]

The table below sets out the structure of Ergon Energy's proposed Residential Basic inclining block tariff.[112] Ergon Energy's proposed Business Basic inclining block tariff has a similar structure but with different thresholds for the consumption blocks.

Table 18.4 Ergon Energy's proposed inclining block tariff structure for residential customers

Charging parameter	Unit	Basis of kWh Charge	
		To	From
Fixed Charge	c/day		
Block 1	c/kWh	0	10,000
Block 2	c/kWh	10,001	20,000
Block 3	c/kWh	20,001	30,000
Block 4	c/kWh	30,001	40,000

109 NER, cll. 6.18.5(f) and (h).

110 NER, cl. 6.18.5(i).

111 Note that the inclining block tariff is currently only conveyed to Ergon Retail given that the Queensland Competition Authority has adopted Ergon Energy's flat structure at the regulated retail tariff level.

112 The proposal is more complex than the existing inclining block tariff, which is comprised of a fixed charge and three consumption blocks.

Charging parameter	Unit	Basis of kWh Charge	
		To	From
Block 5	c/kWh	40,001	50,000
Block 6	c/kWh	50,001	60,000
Block 7	c/kWh	60,001	70,000
Block 8	c/kWh	70,001	80,000
Block 9	c/kWh	80,001	90,000
Block 10	c/kWh	90,001	100,000

Source: Ergon Energy.

To address our concerns, Ergon Energy must demonstrate that the annual level of electricity consumption and the peak capacity requirement, as measured by the individual customer's annual level of peak demand, are highly correlated. Our concerns could also be addressed by adopting a flat tariff structure for residential and small business customers with a basic accumulation meter. We consider a flat tariff structure for these customers contributes to compliance with the pricing principles in the Rules because it is more easily understood by customers, as discussed in Appendix B of this draft decision. We also consider a flat tariff to be a less distortive method to recover residual costs compared to an inclining block tariff.[113]

For its small business customers, adopt an inclining block tariff similar in structure to Endeavour Energy's inclining block tariff if it can demonstrate that it will deliver a smoother transition path for larger energy users to a more cost reflective demand tariff.[114]

We encourage Ergon Energy to seek feedback on whether its small business customers prefer a re-designed inclining block tariff or flat tariff structure.

As noted above, Ergon Energy also proposes to re-assign existing customers with smart meters to its new inclining block tariff. We discuss our assessment of this proposal against the requirements in the Rules in Section 18.5.3 of this draft decision.

More research and engagement required on capacity tariff

Ergon Energy proposes to introduce capacity tariffs on 1 July 2020 for residential and small business customers on a voluntarily opt-in basis.

[113] To the extent that residual costs are recovered by applying a mark-up to the anytime energy charge under this tariff structure.

[114] AER, *Draft decision—Tariff structure statement proposals—Ausgrid, Endeavour Energy and Essential Energy*, August 2016, pp. 56-57.

We consider this proposal to be an important element of the tariff structure statement as it represents what Ergon Energy believes is the most cost reflective network tariff for residential and small business customers, and reflects their long term strategy for tariff reform.[115] We commend Ergon Energy for developing innovative tariff structures, such as the capacity tariff (and the previously consulted upon but later discontinued residential lifestyle and business package plans).[116] Proposing tariffs that challenge conventional wisdom encourages new ways of thinking about how best to design and implement more cost reflective pricing structures.

However, we are not satisfied that the design of Ergon Energy's proposed opt-in capacity tariffs contributes to compliance with distribution pricing principles. This is because we are not convinced that this proposal represents an improvement over a demand tariff from an economic efficiency perspective.[117] We also have concerns over the complex nature of this proposal.[118] We encourage Ergon Energy to trial the use of capacity tariffs during the 2020–25 regulatory control period, rather than including capacity tariffs in its TSS. The learnings from these trials and further stakeholder consultation can then be reflected in Ergon Energy's TSS proposal for the 2025–30 regulatory control period.

(i) Proposed capacity tariff structure

The specific design features of Ergon Energy's proposed opt-in residential capacity tariff structure are shown in the table below. The structure of its proposed capacity tariff for small business customers is similar to the proposal for residential customers, except that the peak charging window applies only to workdays.[119]

We consider this proposal to be a more complicated version of a demand tariff, rather than a capacity tariff given that it is based on the customer's maximum kW demand, rather than the customer's installed network capacity as measured at their metering or connection point.

Table 18.5 Ergon Energy's proposed default capacity tariff structure for residential customers

Charging parameter	Unit	Description of charging parameter	Charging window definition
Fixed charge	c/day	This is a daily charge that is applied on a $ per day basis to each energised connection point, regardless of the level of usage.	N/A

115 Ergon Energy, *Tariff Structure Statement - 2020–25 Regulatory Control Period - Explanatory note*, June 2019, p.8

116 For more information, refer to link: www.ergon.com.au/network/network-management/network-pricing/lifestyle-network-tariff

117 NER, cl. 6.18.5(f).

118 NER, cl. 6.18.5(h)(i).

119 Ergon Energy defines work days to be weekdays excluding government specified public holidays.

Charging parameter	Unit	Description of charging parameter	Charging window definition
Anytime energy charge	c/kWh	This charge is applied on a cents per KWh basis for the total energy consumption recorded under this tariff during the billing period.	N/A
Day-time maximum demand charge	c/kW/m	This is a monthly charge that is applied on a $ per kilowatt (kW) for the maximum kW demand recorded during the day time charging window.	10am to 4pm each day
Evening time maximum demand charge	c/kW/m	This is a monthly charge that is applied on a $ per kilowatt (kW) for the maximum kW demand recorded during the evening time charging window.	4pm to 9pm each day

Source: Ergon Energy.

Important design features of the proposed capacity tariff are that:

- customers (or their retailers) are required to select their capacity threshold prior to being re-assigned to this tariff, and
- excess capacity charges are imposed in the event of a customer's actual peak maximum demand during the billing period exceeding their selected capacity threshold.

Ergon Energy proposes to limit the choice of capacity threshold for both residential and small business customers to the kW bands shown in the table below.

Table 18.6 Ergon Energy's proposed capacity thresholds

Capacity tariff	Residential (kW)	Small Business (kW)
1	2.5	2.5
2	4.5	4.5
3	7	7
4	10	10
5	15	15

Source: Ergon Energy.

The choice of capacity threshold is important because the higher the selected kW capacity threshold, the higher the fixed charge applied under the capacity tariff. [120] The choice of capacity threshold is also important because it influences the probability that the customer will be required to pay an excess capacity charge in the future. This is because the customer is only required to pay an excess capacity charge if their actual kW demand exceeds their selected capacity threshold. If a customer selects a high capacity threshold relative to their actual demand, they are unlikely to be required to pay an excess capacity charge in the future. They will, however, pay a higher fixed charge as a result of selecting a higher kW capacity threshold.

We note that Ergon Energy proposes to give customers some leeway by only applying the excess capacity charge in the situation where a customer exceeds their capacity threshold on three separate days per billing period.[121] We consider this to be a reasonable approach from a customer impact perspective.

(ii) The proposed capacity tariff raises economic efficiency concerns

We are concerned that the proposed capacity tariff has inferior efficiency properties to an equivalent demand tariff. [122] We are not satisfied on the basis of the information in Ergon Energy's tariff structure statement that this form of cost reflective pricing will deliver additional economic benefits to consumers to offset the additional transaction costs compared to a well-designed demand tariff or time-of-use energy tariff. We note that a distributor is only allowed to depart from economic efficiency principles in the Rules[123] to the extent that it is reasonably necessary to do so to satisfy the customer impact principles.[124]

Our concern over the efficiency properties of the capacity tariff proposal are based on the potential for the 'capacity charge mechanism' to create perverse economic incentives that encourage customers to make inefficient decisions about their peak usage of network. This issue is explored in detail in Appendix B to this draft decision.

It is our understanding from the tariff structure statement that Ergon Energy proposes to use the proposed evening capacity charge to calculate the fixed charge and the excess capacity charge.[125] This is likely to result in retailers seeking to minimise their transaction costs by selecting the lowest possible capacity threshold on behalf of their customers given that there is no effective penalty for doing so - the unit price per kW of peak maximum demand is the

120 For example, the fixed charge applying to kW capacity threshold Band 1 is equal to the evening peak capacity charge, expressed on a $ per kW per month basis, multiplied by the 2.5 kW capacity allowance for Band 1.

121 Ergon Energy*, 2020–25 Tariff Structure Statement*, June 2019, p. 27-29.

122 NER, cll. 6.18.5(f) and (g).

123 NER, cll. 6.18.5(f) and (g).

124 NER, cll. 6.18.5(h) and 6.18.5(i).

125 We note that the indicative network use of system price level of the capacity charge is higher than the equivalent charge under the default demand tariff. There is no explanation provided in the updated tariff structure statement for this price difference.

same. The capacity tariff will under these circumstances have similar properties to a simple demand tariff. It is possible that this design feature may not reflect the underlying intention of Ergon Energy. It highlights the need for Ergon Energy to engage more constructively with retailers and other key stakeholders to ensure that the tariff is designed to achieve its intended purpose.

(iii) It is difficult for customers to understand and respond to the proposed capacity tariff

On the basis of the information in Ergon Energy's proposal, we are not convinced that the capacity tariff proposal satisfies the customer impact principle in the Rules.[126] Given the complex nature of this proposal, together with the requirement for customers to take a more active role in the tariff setting process, the introduction of this form of cost reflective pricing has the potential to impose significant risks and transaction costs on customers and retailers. We consider that it is important for distributors to take into account the needs of their customers when designing their cost reflective tariff structures. In this regard, we note that the Queensland distributors are at the beginning of the tariff reform journey with only a limited number of residential customers currently on cost reflective tariffs.[127] As a consequence, the majority of residential and small business customers in Queensland will not be familiar with kW demand concepts, and many of these customers are not likely to be currently actively engaged in the electricity market.[128]

(iv) Capacity tariffs should not be introduced in the 2020–25 regulatory control period

Given our concerns, we consider that it is prudent for the Queensland distributors to delay the introduction of a capacity tariff, even on an opt-in basis, and to work with stakeholders and the AER to undertake a comprehensive trial of a range of capacity tariff structures during the 2020–25 regulatory control period. In this way the Queensland distributors will be better placed in terms of empirical evidence to develop a more considered capacity tariff proposal for possible introduction in the 2025–30 regulatory control period. By that time it is envisaged that a significant proportion of customers in Queensland will have become more familiar with the concept of kW demand charging[129], which will prove to be a useful stepping stone towards these more complex tariffs.

It also provides the Queensland distributors with opportunity to work constructively with retailers and other key stakeholders to develop a comprehensive education plan to address the existing knowledge gaps of customers and to clearly explain how the capacity tariff

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[126] NER, cll. 6.18.5(h) to (i).

[127] Refer to Appendix A of this draft decision for more information on the penetration of smart metering and cost reflective pricing in the residential and small business customer segment by distributor.

[128] Energy Consumers Australia, *Energy Consumer Sentiment Survey*, June 2019, p. 41.

[129] This assumes that the QLD distributors adopt a transitional demand tariff as their default tariff for smart metered customers in the 2020–25 regulatory control period.

addresses the long-term challenges facing the Queensland distributors, particularly in regard to the technology driven changes in the way their customers are using the electricity network. Also, to develop with the assistance of stakeholders appropriate complementary measures aimed at assisting customers expected to be worse off under the capacity tariff option.

We also consider that it is important for the Queensland distributors to give careful consideration to how to improve the economic efficiency of capacity charging parameter when designing tariffs to trial in the next regulatory control period. We consider there is merit in testing a seasonal capacity tariff option given that residential demand for network capacity is at its highest in the summer months of the year. As previously discussed, we also think that there is merit in testing a trial capacity tariff that also contains time-of-use energy charges.

It will also be critical for the Queensland distributors to explore the issue of whether the capacity charging parameter should be designed for the purpose of signalling long run marginal cost or the efficient recovery of residual costs. The purpose will play a major role in shaping the design of the tariff trial.

We encourage the Queensland distributors to learn from the recent experience in other jurisdictions where complex tariff structures have been successfully introduced, such as Endeavour Energy. For more information on the recent experience of distributors in other jurisdictions, refer to Appendix B of this draft decision.

We support allowing customers on transitional retail tariffs to opt-in to TOU tariff

Ergon Energy proposes to introduce a new time of use energy tariff in the next regulatory control period. The purpose of this tariff is to mitigate the future bill impacts associated with the expiration of transitional retail electricity tariffs.[130] This is the reason that Ergon Energy proposes these new tariffs to have the same structure as the transitional retail tariffs. It is clear from the tariff structure statement that it is not Ergon Energy's intention to allow other customers to opt-in to these time of use tariffs.

While we support in principle this proposal, we require that Ergon Energy provide customers impacted by this proposal with greater certainty in regard to transition path for this tariff. The revised tariff structure statement must also provide greater justification that the proposed structure of these tariffs comply with the pricing principles in the Rules. we also recommend Ergon Energy reassess whether there is a need for a specific impact-mitigation measure to be introduced for these customers given that their underlying concerns may be directly addressed by our requirement for the price level of the demand charging parameter under both existing and proposed demand tariffs to be reduced in the first year of the regulatory

[130] Ergon Energy, *2020–25 TSS Explanatory notes*, June 2019, p. 20.

control period and then transitioned to long run marginal cost over at least a ten year time frame.

We expect Ergon Energy to engage constructively with its stakeholders on this important issue as part of the revised tariff structure statement, including the provision of robust customer impact analysis and indicative pricing scenarios.

We support in principle the proposed controlled load tariffs

The Queensland distributors propose to expand their suite of controlled load tariffs by introducing new controlled load tariffs for low voltage connected business customers.[131]

The following table provides an example of the annual indicative Distribution Use of System (DUoS) prices under Ergon Energy's proposed suite of controlled load tariffs for the 2020–25 regulatory control period.[132]

Table 18.7 Ergon Energy indicative DUoS prices for controlled load tariffs

Commence	Tariff	Charging parameter	2021	2022	2023	2024	2025
Existing	Volume Night Controlled	Anytime energy charge (c/kWh)	2.84	2.91	2.98	3.05	3.12
Existing	Volume Controlled	Anytime energy charge (c/kWh)	2.84	2.91	2.98	3.05	3.12
Proposed introduction on 1 July 2020	SAC Small Load Control Tariff A	Fixed charge (c/day)	125	128	131	134	137.5
		Anytime energy charge (c/kWh	2.84	2.91	2.98	3.05	3.12
Proposed introduction on 1 July 2020	SAC Large Load Control Tariff A East	Fixed charge (c/day)	25	25.6	26.2	26.9	27.5
		Anytime energy charge (c/kWh)	4.8	4.92	5.04	5.16	5.28
Proposed introduction on 1 July 2020	SAC Large Load Control Tariff B	Anytime energy charge (c/kWh)	4.8	4.92	5.04	5.16	5.28

Note: NUoS prices exclude GST. Prices have been rounded for presentation purposes.

Source: Ergon Energy 2019

131 These proposed tariffs are not available to customers with dedicated connection assets coupled at the 11 k distribution network.

132 Note that the Network Use of System (NUoS) prices for the controlled load tariffs vary by transmission pricing region.

The tariff structure statements also provide some information on the terms and conditions attached to these proposed controlled load tariffs, as summarised in Table 18.8 below.

Table 18.8 Proposed terms and conditions for controlled load tariffs

	Tariff	Description
Existing	Volume Night Controlled	Specified connected appliances being controlled by network equipment so supply will be permanently available for a minimum period of 8 hours per day during time periods set at the absolute discretion of Ergon Energy. Full terms and conditions are provided in Ergon Energy's annual pricing proposal.
Existing	Volume Controlled	Specified connected appliances being controlled by network equipment so supply will be permanently available for a minimum period of 18 hours per day during time periods set at the absolute discretion of Ergon Energy. Full terms and conditions are provided in Ergon Energy's annual pricing proposal.
Proposed introduction on 1 July 2020	SAC Small Load Control Tariff A	This tariff is available to small business customers with basic or smart metering and will subject to the terms and conditions set out in the annual pricing proposal.
Proposed introduction on 1 July 2020	SAC Large Load Control Tariff A	This tariff is available to large business customers at the absolute discretion of Ergon Energy. Total connected load is controlled by network equipment so that supply will be available for a minimum period of 18 hours per day during time periods set at the absolute discretion of Ergon Energy.
Proposed introduction on 1 July 2020	SAC Large Load Control Tariff B	This tariff is available to large business customers at the absolute discretion of Ergon Energy. Specified connected appliances are controlled by network equipment so that supply will be available for a minimum period of 18 hours per day during time periods set at the absolute discretion of Ergon Energy.

Source: AER analysis.

We do not consider that the Queensland distributors have clearly demonstrated in their tariff structure statements that their proposal to expand the suite of controlled load tariffs in the 2020–25 regulatory control period is consistent with the distribution pricing principles in the Rules.

We are not convinced that there is a strong economic case to expand the suite of controlled load tariffs in light of the economic circumstances of the Queensland distributors, namely excess capacity and expectations of minimal peak demand growth in the foreseeable future. Nevertheless, we accept that there may be a long-term economic rationale for the expansion of controlled load tariffs given the nature and extent of the on-going transformation of the energy sector. We are not clear on how this proposal will contribute to addressing these challenges, particularly given that in the long-term most customers will be on a cost reflective tariff. Stakeholders have also raised similar concerns.[133] [134] To address this concern, the Queensland distributors must demonstrate in their tariff structure statements how this proposal satisfies the long run marginal cost principle[135] and contributes to the efficient allocation of residual costs.[136]

We also note that the proposed controlled load tariffs are capable of acceptance under the Rules if the Queensland distributors are able to clearly demonstrate that these proposed tariffs alleviate the impact on customers under cost reflective tariffs.[137] In this regard, we note the feedback received from stakeholders in the agricultural sector, such as the QLD canegrowers and Pioneer Valley Water that have consistently argued that the irrigators will face unacceptable bill impacts as a consequence of the introduction of cost reflective pricing.[138] [139] We could not assess these tariff proposals against the customer impact principles in the Rules given that the updated tariff structure statement are deficient in the following regards:

- The provision of evidence or analysis that clearly shows that the proposed cost reflective tariffs will not impose unacceptable bill impacts on particular types of customers, such as irrigators.
- The provision of evidence or analysis that clearly show that the proposed controlled load tariffs are capable of mitigating the impact of customers adversely impacted under cost reflective pricing.

We are confident that the Queensland distributors will provide greater clarity over the customer impacts in their revised tariff structure statements given the work currently being undertaken by the University of NSW and CSIRO. To achieve compliance with the Rules, the Queensland distributors must provide in their revised tariff structure statements greater clarity in regard to the following aspects of their controlled load tariff proposal:

- The future level of the inherent discount under these tariffs.[140]
- Which customers are eligible to take-up the controlled load tariffs.[141]

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133 ECA, *Submission to AER Issues paper - 2020–25 Regulatory Control Period - Energex and Ergon Energy*, June 2019.

134 QCOSS, *Submission to AER Issues paper - 2020–25* Regulatory Control Period - Energex and Ergon Energy, June 2019.

135 NER, cl. 6.18.5(f).

136 NER, cl. 6.18.5(g).

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

138 Pioneer Valley Water Ltd, *Correspondence to the AER*, February and March 2019. This correspondence is available from: www.aer.gov.au/node/63380

139 Canegrowers*, Response to QLD electricity distribution determinations - Energex and Ergon Energy 2020–25*, 14 June 2019. This document is available from: www.aer.gov.au/system/files/Queenslandper cent20Canegrowersper cent20per cent20-per cent20Submissionper cent20onper cent20Energexper cent27sper cent20Regulatoryper cent20Proposalper cent202020–25per cent20-per cent20TSSper cent20-per cent2014per cent20Juneper cent202019.pdf

140 We note that the current indicative pricing schedule suggest that the QLD distributors do not propose to re-balance these proposed new controlled load tariffs i.e. uniform per cent price increase by charging parameter across all tariffs.

141 We note that the QLD distributors propose in their updated TSS proposal for the eligibility to opt-in to these tariffs to be either at the absolute discretion of the QLD distributor or to be set out in their annual pricing proposal.

> We require this clarity to ensure that we have sufficient information to assess whether the proposed controlled load tariffs satisfies the customer impact principle in the Rules.

We note that the controlled load tariff is of particular importance to the irrigators. We encourage the Queensland distributors to work more constructively with these stakeholders during their preparations for the revised tariff structure statement given that their feedback will be critical to ensuring that our concerns are appropriately addressed.

Hardship customers should not be allowed to opt-in to legacy tariffs

The Queensland distributors propose to allow hardship customers[142] that are re-assigned to a more cost reflective tariff in the next regulatory control period to opt-in to the legacy anytime energy tariffs.[143] We note that the legacy tariffs are proposed to be set at a level that does not reflect their proposed reduction in their revenue requirement in the first year of the 2020–25 regulatory control period.

On the basis of the information in the tariff structure statement we are not convinced that this proposal complies with the pricing principles in the Rules. Specifically we are not satisfied that this proposal is consistent with the customer impact principle in the Rules.[144] The Queensland distributors have provided no evidence that the customers on retail hardship programs will be worse off as a consequence of being re-assigned to a cost reflective tariff. There is no analysis on the extent that these customers, if they were to be worse off, are able to mitigate this impact by managing their peak usage, upgrading to more efficient appliances or taking up a cheaper controlled load tariff. It is not clear to us that allowing these customers to opt-in to the legacy tariff will result in these customers being better off, particularly given the Queensland distributors intend for this tariff to be relatively expensive by not reflecting the proposed revenue reduction in the regulatory proposal. We also note that the updated tariff structure statement is silent on how these customers will be ultimately transitioned to cost reflective tariffs. In the absence of a clear transition strategy, there is a considerable risk under this proposal that retail hardship customers will remain on legacy tariffs for many years. We do not consider this outcome to be in the long-term interests of these customers.

It is important to note that we support the efforts of distributors to design their tariff reform to mitigate the customer impact of introducing more cost reflective pricing. The customer impact principle in the Rules provides guidance to distributors on how they should mitigate customer impacts if it is necessary to do so given their circumstances, such as by transitioning prices to efficient levels over time[145] and providing customers with greater tariff choices.[146] It will also be important for the Queensland distributors to work with retailers and

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142 The QLD distributors propose to define hardship customers to be any customers enrolled in a retailer hardship program.

143 Ergon Energy, *2020–25 Tariff Structure Statement Explanatory notes*, June 2019, p. 9.

144 NER, cl. 6.18.5(h).

145 NER, cl. 6.18.5(h)(1).

146 NER, cl. 6.18.5(h)(2).

other relevant parties to educate their customers on cost reflective tariffs, particularly where the customer impact analysis has identified particular customer cohorts that are likely to be adversely impacted by the introduction cost reflective pricing, particularly where these customers are vulnerable.

We encourage the Queensland distributors to work with their stakeholders to take account of these approaches to customer impact mitigation when developing their revised tariff structure statement.

How can the tariff structure statement be improved from a compliance perspective?

We have drawn from our recent TSS decisions in other distributors to provide the Queensland distributors will guidance on how they can improve their tariff structure statement from a compliance perspective. We encourage the Queensland distributors to learn from the experience of other distributors to ensure that they are better placed to respond to the compliance concerns raised in this draft decision and the needs of its stakeholders.

(i) Most customers should benefit from cost reflective tariffs

It is important for distributors in the early stages of the tariff reform process to carefully manage the customer impact of introducing cost reflective pricing given the following considerations:

- The majority of their customers have little, if any, knowledge of more complicated pricing concepts such as time of use pricing.
- Existing customers have made past investments in household appliances, solar PV system and other electrical equipment based on the incentives inherent in existing legacy tariffs.
- It will also take time for existing customers to change their behaviour in response to the new incentives under cost reflective pricing and to upgrade their appliance stock.

Distributors should also design their cost reflective tariffs in a manner that is appropriate for their economic circumstances. In this regard, we note that the Queensland distributors can take a more considered approach to the introduction of cost reflective pricing given that there will be a minimal efficiency loss from doing so given their economic circumstances of widespread excess capacity and minimal growth in peak demand into the foreseeable future.

To ensure that the introduction of cost reflective pricing does not result in unacceptable impacts on customers, our recent TSS decisions have required that some distributors set their tariffs during the regulatory control period to comply with specific constraints set out in our final decision. For example our final TSS decision requires that Endeavour Energy set their annual tariffs during the 2019-24 regulatory control period so that:

- no more than 10per cent of customers have a financial incentive, at the network level, to opt-out of the cost reflective demand or seasonal time of use tariff to the flat tariff.

- at least 50per cent of customers have a financial incentive, at the network level, to choose the cost reflective demand tariff over the transitional demand tariff.[147]

We consider that there is merit in the Queensland distributors adopting a similar approach to the setting of the annual relativities between legacy tariff and more cost reflective tariffs during the next regulatory control period. We expect the Queensland distributors to provide more certainty and transparency in relation to this issue in their revised tariff structure statement. We encourage the Queensland distributors to engage their stakeholders on this issue.

(ii) We recommend that customers be given a choice of cost reflective tariff structures

We recommend that the Queensland distributors introduce a time use of energy tariff on an opt-in basis. We consider that giving customers the ability to choose between a suite of cost reflective tariffs gives them the ability to choose the tariff they understand best—and presumably will therefore respond to — and mitigates any potential adverse cost impacts from the move to cost reflective tariffs. Empowering customers in this way is likely to engender greater customer acceptance of change. We also consider that it promotes the achievement of the network pricing objective in the Rules[148] if this time of use tariff is designed to be as cost reflective as the default demand tariff.

Our recent decisions in other jurisdictions have resulted in distributors providing their customers with a choice of cost reflective tariffs, as summarised in Table 18.9 below.

Table 18.9 Examples of AER approved cost reflective tariff portfolios

Distributor	Default Tariff	Option Cost reflective tariffs
Ausgrid	Demand tariff	Seasonal TOU tariff TOU demand tariff
Evoenergy	Residential kW Demand tariff	Time-of-Use tariff
Endeavour Energy	Transitional Demand tariff	Demand tariff seasonal Time of Use tariffs

Source: AER analysis.

147 Endeavour Energy, *2019-20 Pricing Proposal*, May 2019, p. 33. This document is available from: https://www.aer.gov.au/system/files/Endeavourper cent20Energyper cent20-per cent202019-20per cent20Pricingper cent20Proposalper cent20Finalper cent20-per cent20Mayper cent202019.pdf

148 NER, cl. 6.18.5(a).

Consistent with our recommendation to adopt a transitional demand tariff as their default tariff, we consider that the Queensland distributors can improve their tariff structure statement from a compliance perspective by adopting a similar approach to Endeavour Energy.[149] This will require that the Queensland distributors include in their revised tariff structure statement an opt-in time of use tariff for residential and LV-connected business customers. We encourage the Queensland distributors to constructively engage with their stakeholders on this element of our draft decision prior to submitting a revised tariff structure statement to the AER in December 2019.

18.5.4 Proposed tariffs for medium and large business customers

This section of our draft decision covers our assessment of Ergon Energy's specific tariff reform proposals relating to medium and large business customers in the 2020–25 regulatory control period.

We consider the existing tariff structures of the medium[150] and large business customers to be cost reflective in Queensland.[151] We note that in some respects Ergon Energy's tariff structures for these customers could be argued to more cost reflective than Energex given that Ergon Energy's peak charging parameters better reflect the seasonal pattern of network usage.

This section is structured to provide our assessment of the following elements of Ergon Energy's proposed changes to the tariffs for medium and large business customers:

- The proposed introduction of kVA pricing for Standard Asset Customers.
- The proposed grandfathering of the existing cost reflective tariffs.
- The proposal removal of the excess kVAr charges.
- The proposed reassignment of customers to an individually calculated tariff that are identified as being 'outliers' from a cost to serve perspective.
- The proposed methodology for allocation of residual costs to the medium and large business customers.
- The proposed methodology for signalling long run marginal costs to medium and large customers.

149 AER, *Attachment 18 - Tariff structure statement - final decision - Endeavour Energy 2019-24 Regulatory control period*, April 2019.

150 We have defined medium business customers to be all business customers connected at the low voltage level of the electricity distribution network with annual electricity consumption greater than 100 MWh pa

151 We have defined large business customers to be business customers that do not satisfy our definition of small and medium business customers.

(i) More detailed information on the proposed introduction of kVA pricing is needed

Ergon Energy proposes to introduce a kVA basis to the demand charging parameter for certain classes of business customers in the next regulatory control period. We support in principle this proposal given that it will result in an improvement in the cost reflectivity of the marginal price signals for these customers. It is also consistent with the pricing practices of distributors in other jurisdictions in the NEM. Ergon Energy recognises that some of the customers impacted by this proposal will need to incur significant costs to upgrade their metering to accommodate this change. To address this issue, Ergon Energy proposes to allow customers to opt-in to a kW demand charge tariff. While we support in principle the inclusion of this type of customer impact mitigation measure, it is not sufficient for access to this tariff to be at the discretion of the distributor. To achieve compliance with the distribution pricing principles in the Rules, we require that the revised tariff structure statement provides more detailed information on this proposal. At a minimum, we require Ergon Energy to provide us with the following:

- An understanding of the potential number of customers that will be impacted by this proposal.
- An understanding of the magnitude of the financial impact, both in terms of additional metering upgrade costs and network bill increases for customers with a poor power factor.
- An understanding of the proposed financial impact threshold or trigger that must be exceeded in order for the customer to be eligible to be reassigned from the kVA-based demand tariff to kW-based demand tariff.

We also consider that there is a merit in exploring whether there is a need for a customer impact mitigation measure in respect to this proposal given that we require Ergon Energy to transition its demand charges to long run marginal cost over a reasonable period of transition. We encourage Ergon Energy to explore this issue with relevant stakeholders as part of their engagement activities for the revised tariff structure statement.

(ii) We are not convinced that the proposed default tariff is superior to the existing demand tariffs

We note that Ergon Energy proposes to introduce a new default demand tariff for the Standard Asset Connection (SAC) large customers from 1 July 2020.[152] The existing default tariffs are proposed to either be converted to an opt-in basis or grandfathered.[153]

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152 Standard Asset Connection (SAC) customers are defined as customers that are connected to the 11kV or higher voltage level of the electricity distribution network that are not assigned to an individually calculated tariff.

153 Ergon Energy, *Tariff Structure Statement - 2020–25 Regulatory Control Period - Explanatory note*, June 2019, p. 21.

We are not completely satisfied that this element of the updated tariff structure statement complies with the pricing principles in the Rules. We understand that the primary motivation for this proposal is to achieve consistency with Energex. We do not consider that this is a sufficient rationale to be compliant with the Rules, particularly as the existing default tariffs are superior from an efficiency perspective given that they better reflect the seasonal nature of network utilisation in Ergon Energy's network. We are also concerned that the replacement of the small, medium and large default tariffs with a single default demand tariff could exacerbate the bill impacts associated with customers that exceed the 100 MWh pa threshold and are required to be re-assigned to this proposed demand tariff. We note that these customers have the option of being reassigned to the existing legacy demand tariffs, but there is insufficient information in the updated tariff structure statement on the extent that taking up this option will address these concerns. We encourage the Queensland distributors to provide more information in their revised tariff structure statement to address our concerns.

(iii) We support the removal of the excess kVAr charge

Ergon Energy proposes to remove the excess kVAr charge from 1 July 2020 on the grounds that this charge is no longer required because of the efforts made by customers to improve their average power factor.[154] We accept that this proposal contributes to the compliance with the pricing principles.[155] We note that it will simplify the tariff structure for these customers without having a material adverse impact on the efficiency properties of the tariff structure. We are not aware of any customer impact issues arising from the removal of this charging parameter.

(iv) We seek clarity on the reassignment of 'outlier' customers to an individually calculated tariff

Ergon Energy proposes to reassign customers in the Connection Asset Customer (CAC) tariff class to the Individually Calculated Customer (ICC) tariff class in 2020–25 regulatory control period, where they have been identified as being an outlier in terms of cost per kVA.[156] While we accept that this proposal may result in improved economic outcomes, we cannot on the basis of the information set out in the updated tariff structure statement assess this proposal as compliant with the Rules.

To achieve compliance with the distribution pricing principles in the Rules, we require that Ergon Energy provide more detailed information on this proposal in their revised tariff structure statement, as summarised below:

- A detailed description on the proposed approach to identifying customers that are an outlier from a cost to serve basis.

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[154] Ergon Energy, *Tariff Structure Statement - 2020–25 Regulatory Control Period*, June 2019, p. 18.

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

[156] Ergon Energy, *Tariff Structure Statement - 2020–25 Regulatory Control Period - Explanatory note*, June 2019, p. 20.

- A detailed description of the proposed methodology for estimating the cost to serve of an individual customer. This description will need to provide a clear explanation of the following:
    - The proposed methodology for the application of long run marginal cost to charging parameter and whether it is proposed to transition the peak price to an efficient level.
    - The proposed methodology for the allocation of residual distribution costs from tariff class to tariff level and across charging parameter within a given tariff.
    - The proposed methodology for setting designated pricing proposal charges, including the proposed linkage, if any, to the transmission charges set by Powerlink in its capacity as the jurisdictional transmission network service provider in Queensland.
- An indication of the potential number of customers that could be identified as being 'outliers' from a cost to serve perspective and the extent that these customers will be adversely impacted by being re-assigned to a more cost reflective site-specific individually calculated tariff.
- A detailed description of the measures that Ergon Energy proposes to mitigate the customer impact of this proposal, including any transitional pricing arrangements or opt-out tariff provisions.
- A detailed description of the proposed engagement process that Ergon Energy intends to follow to ensure that customers impacted by this proposal are given adequate advance notice to enable them to fully understand the likely tariff implications and to explore opportunities to mitigate the impact of these tariff changes.

We also consider that our concerns over this proposal also reflects a general lack of clarity provided in the updated tariff structure statement in regard to the proposed eligibility criteria associated with the ICC tariff class. We accept the criteria relating to the connection characteristics of the customer, such as the requirement that the customer have an installed capacity of 10 MW or greater, satisfies the requirements in the Rules. We have concerns about the more subjective nature of the proposed eligibility criteria, such as where the Queensland distributor makes the assessment that the nature of the customer's connection to the electricity distribution network makes it appropriate for individually calculated tariffs to apply to a customer.[157] To achieve compliance with the Rules, we require the Queensland distributors to provide greater clarity over these criteria in their revised tariff structure statement.

We encourage Ergon Energy to engage constructively with its stakeholders on this element of its proposal, as the key issue is to ensure that this proposal adequately addresses our concerns over the potential for this proposal to impose unacceptable customer impacts.

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[157] Ergon Energy, *Tariff Structure Statement - 2020–25 Regulatory Control Period*, June 2019, p. 16.

(v) More clarity is needed over the allocation of residual costs

We require that the Queensland distributors provide more detailed information in their revised tariff structure statement on how they propose to allocate their residual costs to the individual tariff level and across individual charging parameters. This is particularly necessary for the individually calculated tariffs, where the efficiency properties of these tariff depend on the extent that the distributor proposes to pass through the site-specific costs, such as those relating to the provision of electricity transmission services. It should also be noted that these tariffs can cause significant economic harm if they result, for example, in these customers inefficiently by-passing the electricity distribution network.

(vi) Peak demand charges should be transitioned to long run marginal cost

As with the cost reflective tariffs in the residential and small business customer segment, we require that the Queensland distributors transition the peak demand charging parameter to long run marginal cost for the medium and large business customers. We consider that there are likely to economic benefits from encouraging these customers to improve their utilisation of the network, where this is not expected to result in network congestion in the foreseeable future and the need to augment the electricity distribution network. It will be important that the Queensland distributors engage constructively with their stakeholders on the extent that it is appropriate to reduce these demand charges on 1 July 2020 and the extent that these charges should be increased in the future towards long run marginal costs given the extent that future demand growth is expected to absorb excess capacity.

18.6 Long run marginal cost methodology

The Rules require that distributors include in their tariff structure statement a methodology for the long run marginal cost. This methodology must explain how the distributor estimates long run marginal cost and how these estimates are applied to tariffs.

The Queensland distributors have proposed a new methodology for the estimation of long run marginal cost, which is similar to the '500 MW' model some electricity distributors use in the United Kingdom. We commend the Queensland distributors for exploring other approaches to estimating LRMC and not simply adopting the standard industry approach used by electricity distributors in Australia (the so-called Average Incremental Cost approach). Exploration of different approaches in itself expands the knowledge base, which provides impetus for further improvements to LRMC estimation methods. This in turn provides a superior basis for developing cost reflective tariffs.[158]

On balance, we consider Ergon Energy's proposed approach to estimate long run marginal costs (LRMC) contributes to compliance with the distribution pricing principles and to the achievement of the network pricing objective at this stage of the tariff reform process.

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

However, we have several concerns regarding the proposed approach and we require Ergon Energy to address these concerns in its next tariff structure statement. In particular, we encourage Ergon Energy to develop an LRMC estimation method that has greater regard to the state of its network.

It is important to note that we require that Ergon Energy's LRMC estimates be used in the price-setting process as cost-reflectivity targets, rather than as binding figures that peak charging parameters must equal. That is, the price levels of peak charging parameter must be transitioned towards the LRMC estimate over time, subject to other pricing principles.[159] While there is spare capacity in Ergon Energy's network at present, it is arguable LRMC estimates for the 2020–25 regulatory control period would be low—perhaps close to zero in large parts of the network—depending on the calculation method. On the other hand, there is uncertainty how long such a state would persist given rapid technological developments.

Given this uncertainty, we consider transitioning LRMC-based charging parameters to a cost-reflectivity target could be prudent while there is spare capacity in Ergon Energy's network for the foreseeable future. Such a transition, combined with appropriately-defined charging windows, could be part of a longer term transitional strategy to increase awareness of cost-reflective tariff structures and potential times of congestion. This could lessen the shock to consumers should network congestion quickly become an issue and necessitate sharper pricing signals.[160]

The sections below set out:

- A summary of the Queensland distributor's methodology for long run marginal cost
- Our assessment of LRMC estimation methodology using the framework set out in Appendix C
- Our assessment of how the LRMC estimates should be applied to tariffs

(i) The proposed long run marginal cost estimation methodology

Ergon Energy used the Long Run Incremental Cost approach to estimate LRMC. This approach is similar to the '500 MW' model some electricity distributors use in the United Kingdom in the sense that it is based on cost of building a hypothetical network to supply a total coincident demand of 500MW, using “building blocks” comprised of modern equivalent assets. Ergon Energy used the optimised replacement costs and associated opex—on an annualised basis—as the expenditure inputs into the LRMC estimation.[161]

159 Ergon Energy, *TSS explanatory notes 2020–2025*, June 2019, p. 32.

160 A gradual transition would mitigate 'status quo bias', which is a tendency to resist change and favour the status quo. See E.V Hobman, et al, *Uptake and usage of cost-reflective electricity pricing: Insights from psychology and behavioural economics*, Renewable and sustainable energy reviews (57), 2016, p. 457.

161 Ergon Energy, *TSS explanatory notes 2020–2025*, June 2019, p. 34.

Ergon Energy stated its model preserved the average spatial characteristics and technical requirements of Ergon Energy's network at various voltage levels and did not build in spare capacity into the hypothetical network. [162] Ergon Energy based the demand connected at each voltage level using its actual network profile and scaled them to 500MW.[163]

The following table shows Ergon Energy's long run marginal cost estimates, expressed on a nominal $ per kVA per annum basis, for the 2020–25 regulatory control period.

Table 18.10 Ergon Energy LRMC estimates by Region - Nominal $/kVA/pa

Voltage level	East	Mt Isa	West
132/110/66/33kV	72	72	107
22/11kV	141	141	360
Low Voltage	226	103	660

Source: Ergon Energy, *TSS explanatory notes 2020–2025*, June 2019, p. 35-36.

Ergon proposes to adjust these estimates by CPI during the regulatory control period.

(ii) Our assessment of proposed LRMC methodology

On balance, we consider Ergon Energy's estimation method is fit for purpose at this stage of tariff reform. However, we have some concerns regarding Ergon Energy's approach to estimating LRMC, as we discuss below. We encourage Ergon Energy to address these concerns when developing its approach to estimating LRMC in its tariff structure statement for the 2025–30 regulatory control period.[164]

We accept that Ergon Energy's proposed approach produces more stable estimates of LRMC compared to its previous approach based on Average Incremental Cost in an environment of minimal peak demand growth.[165] We note that the AEMC considered LRMC is a more appropriate basis than short run marginal cost for network prices because it is more stable—and consumers are likely better able to respond to stable price signals.[166] On the other hand, it is important not to conflate stability in LRMC estimates with their degree of cost reflectivity. Those are separate assessments and we must balance the two factors where they conflict.

[162] Ergon Energy, *TSS explanatory notes 2020–2025*, June 2019, pp. 33–34.

[163] Ergon Energy, *TSS explanatory notes 2020–2025*, June 2019, p. 34; Ergon Energy, *14.009 - LRMC model*, January 2019.

[164] We assume a 5-year regulatory control period will follow the 2020–25 regulatory control period.

[165] Ergon Energy, *TSS explanatory notes 2020–2025*, June 2019, p. 32.

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

We have some concerns regarding Ergon Energy's approach to estimating LRMC, as discussed below.

Ergon Energy's approach relies on 'building' a hypothetical network to meet a 500MW increment in demand. However, Ergon Energy's LRMC models do not account for the spare capacity on its networks. For example, the models do not include a time dimension for the investments required to meet the 500MW incremental demand. That is, Ergon Energy's LRMC estimates signal that the requirement for augmentation is imminent.

We would expect lower LRMC estimates when there is spare capacity in the network because additional use during coincident peak demand is less likely to lead to network congestion, and hence trigger augmentation. Conversely, we would expect LRMC estimates to be higher when there is less spare capacity in the network because augmentations are more imminent.[167]

A further concern is Ergon Energy's approach is 'one-sided' in that it implicitly assumes only one scenario for the future: that of growth. While we have seen growth has historically been the typical scenario for an Australian electricity distributor. We consider scenarios of stagnant or declining growth in demand for electricity distribution network services are more likely given the penetration of DER and new technology. Rapidly developing technologies such as solar PV and battery storage, as well as more efficient appliances, could lower demand for network services. Changes in customer behaviour—which could be influenced by the transition towards more cost reflective tariffs, among other measures—may also trend towards more conservative demand for network services.

We therefore consider Ergon Energy should also consider the implications of stagnant and declining demand growth (see also the 'Incorporation of repex into LRMC' section, below). Ergon Energy can then derive its LRMC estimates having regard to the probabilities of the different scenarios.[168]

Ergon Energy's approach also differs from previous TSS in which distributors also viewed the LRMC estimates as a cost-reflectivity target. For example, the NSW distributors' 2017 TSS also viewed their LRMC estimates as targets to move toward.[169] However, they used forecasts of expenditure and demand as inputs for their LRMC models (based on the

167 AEMC, *Rule determination: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014 p. 128–129.

168 This is not to imply Ergon Energy must derive LRMC estimates through using a probabilistic calculation. Endeavour Energy, for example, produced two separate LRMC estimates: one for areas of stable or decreasing demand, and another for areas of increasing demand. However, Endeavour Energy based its prices on the latter estimates only because Endeavour Energy considered the impact of inefficient signals in growing areas is greater than in areas of declining demand under postage stamp pricing. See Endeavour Energy, *TSS 0.04 Tariff Structure Explanatory Statement*, April 2018, p. 87.

169 For a more detailed discussion, see AER, *Final decision, Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, pp. 95–98.

Average Incremental Cost approach).[170] These forecasts implicitly account for the probabilities of various scenarios of demand growth.

(iii) Incorporation of repex into LRMC

We consider Ergon Energy's exclusion of repex in its LRMC calculations does not contribute to compliance with the distribution pricing principles and to the achievement of the network pricing objective.

Ergon Energy noted its LRIC framework identifies the costs of building an entirely new network to meet a 500MW increment in demand and so does not require repex as an input.[171]

As discussed previously, however, the LRIC framework is appropriate in an environment of increasing demand and expenditure. In Ergon Energy's network, where there is spare capacity, we consider there is scope to consider the possibility of stagnant or declining demand.

We encourage Ergon Energy to explore the inclusion of repex into LRMC calculations in such an environment. For example, Ergon Energy could derive LRMC estimates by investigating the avoided costs of replacement with lower capacity assets in areas of declining demand. This is similar to the LRMC estimation methods of Endeavour Energy and Evoenergy.[172]

(iv) Forecast horizon

Methods such as the average incremental cost approach and the Turvey approach require a distributor's forecast expenditure and forecast demand as inputs to estimate LRMC. A question for distributors is the time horizon for these forecasts.[173] We consider a 10 year forecast horizon, at a minimum, adequately captures the 'long run', refer to Appendix C.

As we discussed above, Ergon Energy's Long Run Incremental Cost framework identifies the costs of building an entirely new (hypothetical) network to meet a 500MW increment in demand. This uses optimised replacement costs, and associated opex—on an annualised basis—as inputs into the LRMC estimation.[174] Hence, the concept of a forecast horizon is

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[170] The NSW distributors used the average incremental cost approach in their 2017 TSS. For a more detailed discussion, see AER, *Final decision, Tariff structure statements: Ausgrid, Endeavour and Essential Energy*, February 2017, pp. 86–89.

[171] Ergon Energy, *Response to information request: AER EGX ERG IR053*, 1 August 2019, p. 5.

[172] For an example of such an approach, refer to link below: www.aer.gov.au/networks-pipelines/determinations-access-arrangements/endeavour-energy-determination-2019-24/proposal#step-57766

[173] Distribution assets can have lives up to 60 years. Distributors must therefore balance the need to adequately reflect the 'long run' in their LRMC estimates against the decreasing accuracy of forecasts far into the future.

[174] Ergon Energy, *TSS explanatory notes 2020–2025*, June 2019, p. 34.

not applicable to Ergon Energy's approach as it does not rely on forecast expenditure and forecast demand to estimate LRMC.[175]

The forecasting horizon would again become a relevant issue in future tariff structure statements to the extent Ergon Energy use approaches that require forecast expenditure and/or forecast demand.

(v) Methodology for applying LRMC to tariffs

In light of our concern above we require that Ergon Energy's LRMC estimates be used in the price-setting process as cost-reflectivity targets, rather than as binding figures that cost reflective charging parameters must equal. That is, tariff levels would trend towards the LRMC estimate over time, subject to the customer impact principle.[176] While there is spare capacity in Ergon Energy's network at present, it is arguable LRMC estimates for the 2020–25 regulatory control period would be low—perhaps close to zero in large parts of the network—depending on the calculation method. On the other hand, there is uncertainty how long such a state would persist given rapid technological developments.

Given this uncertainty, we consider transitioning LRMC-based tariff components to a cost-reflectivity target could be prudent while there is spare capacity in Ergon Energy's network for the foreseeable future. Such a transition, combined with appropriately-defined charging windows, could be part of a longer term transitional strategy to increase awareness of cost-reflective tariff structures and potential times of congestion. This could lessen the shock to consumers should network congestion quickly become an issue and necessitate sharper pricing signals.[177]

Adoption of electric vehicles, for example, are expected to rise in the coming decades, although the adoption rate is uncertain.[178] This would lead to commensurate increases in electricity consumption.[179] Importantly, there is uncertainty regarding the nature of charging behaviour, which could impact the network in different ways. In the absence of appropriate price signals (and/or other incentives), owners of electric vehicles may utilise the network inefficiently, which in turn could trigger inefficient investment.[180] For example, owners of

175 Ergon Energy, *Reset RIN Schedule 1 response*, 31 January 2019, p. 74.

176 NER, cl. 6.18.5(h).

177 A gradual transition would mitigate 'status quo bias', which is a tendency to resist change and favour the status quo. See E.V Hobman, et al, *Uptake and usage of cost-reflective electricity pricing: Insights from psychology and behavioural economics*, Renewable and sustainable energy reviews (57), 2016, p. 457.

178 Energy Networks Australia (ENA) and CSIRO's analysis indicated projections clustered around 20per cent adoption by 2035 (ENA and CSIRO, *Electricity network transformation roadmap: Final report*, April 2017, p. 33).

179 AEMO, *2019 electricity statement of opportunities*, August 2019, pp. 39–40.

180 The ENA and CSIRO, for example, consider slower pricing and incentives reform could add an additional 12,000 MW by 2050 due to a higher degree of unmanaged charging. See ENA and CSIRO, *Electricity network transformation roadmap: Final report*, April 2017, p. 34.

electric vehicles may 'convenience charge' in the absence of appropriate signals.[181] A well-ordered transition to cost-reflective tariffs could ensure electric vehicle charging interfaces with the network as efficiently as possible.

Hence, we consider Ergon Energy's estimates of LRMC in the context of a transitional approach to reflecting these estimates in tariffs is appropriate at this stage of tariff reform and Ergon Energy's network circumstances.

18.7 Residual cost methodology

The rules require network tariffs to be based on long run marginal cost.[182] However, not all of a distributor's costs are forward looking and responsive to changes in electricity demand. For example, distributors may need to replace network assets when they are old and/or have deteriorating conditions. 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 cost.[183]

The Queensland distributors have stated in their tariff structure statement that they propose to minimise distortions to price signals by identifying a charging parameter for each tariff to use to signal long run marginal cost and by recovering residual cost revenue through the remaining charging parameters.[184] They have also stated that they do not apply this approach for a number of legacy and volumetric tariffs, where some residual costs are recovered through the charging parameter that is also used to signal long run marginal cost.

The Queensland distributors have provide some information in their tariff structure statement on how they propose to derive their annual residual costs at the tariff class level.[185] There is minimal description in their tariff structure statement on the proposed methodology to allocate residual costs from the tariff class level to the individual tariff level and across individual charging parameters.

(i) We require greater clarity over the proposed methodology for residual cost

We require that tariff structure statement provide a clear description of the distributor's price-setting approach for both signalling LRMC and the efficient recovery of residual costs as it assists customers and retailers to better understand the underlying basis of their network

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181 AEMO described 'convenience charging' as charging as soon as vehicle owners get home, including during peak hours. AEMO contemplated other possible charging profiles in its forecasting. See AEMO, *2018 electricity statement of opportunities*, August 2018, p. 31.

182 NER, cl. 6.18.5(f).

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

184 Ergon Energy, *2020–25 Tariff Structure Statement*, June 2019, p. 12.

185 Ergon Energy, *2020–25 Tariff Structure Statement*, June 2019, p. 11.

tariffs.[186] It is also promotes pricing certainty by ensuring that distributors do not deviate from the indicative pricing schedules accompanying their tariff structure statement, except due to:

- annual variation in the revenue cap compared to the revenue used to model the indicative pricing schedule
- Annual variations in the forecasts of customer numbers and volumes used to model the indicative pricing schedule.
- Variation to the long-run marginal cost estimate during changes in their forward looking costs and peak demand conditions.

We encourage the Queensland distributors to address this issue in their revised tariff structure statement by adopting a more transparent approach in their revised tariff structure statement, such as the approach taken by TasNetworks.[187]

We consider that the Queensland distributors have also not provided sufficient information in their tariff structure statement to demonstrate that they propose to set price levels under their proposed tariff structures to improve the efficiency of their residual cost recovery[188] to the extent that this is possible under the customer impact principle in the Rules. [189] This is an important issue for the Queensland distributors given their economic circumstances - where the presence of excess capacity means that their residual costs are likely to be dominant component of their annual economic cost to serve.

It is our understanding from the indicative price schedule accompanying the tariff structure statement that the Queensland distributors do not propose to re-balancing their tariffs in the next regulatory control period to improve the efficiency in which they recover their residual costs from customers. This raises concerns from a compliance perspective and is inconsistent with our recent TSS decisions were we required distributors to increase the relative share of residual costs recovered from fixed charges (or charging parameters with similar efficiency properties) to extent that it is possible to do so in a manner that complies with the customer impact principle in the NER. For example, our recent TSS decision for Essential Energy requires that they improve the efficiency of their residual cost recovery by:

- Increasing residential and small business fixed charges by $5 each year.

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186 AER, *Attachment 18, Tariff structure statement, Draft decision - Ausgrid distribution determination 2019–24*, November 2018, p. 18-19.

187 For more information, refer to link below: www.tasnetworks.com.au/config/getattachment/a18257c2-8ee7-4d2a-b092-441fa3707065/tn-pp001-tec-methodology-2019-20-approved-.pdf

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

189 NER, cl. 6.18.5(h).

- Recover more residual cost per customer (on an equivalent customer basis) from less efficient tariffs (e.g. flat tariffs) than more efficient tariffs (e.g. the demand tariff).[190]

On the basis of the information in the tariff structure statement we are unable to assess whether the Queensland distributor's proposed approach to the setting of tariffs to recover residual cost complies with the Rules. To address this issue, we require that the Queensland distributors provide in their revised tariff structure statement:

- more clarity over how they propose to allocate residual costs at the tariff and individual charging parameter level.
- More evidence and analysis to demonstrate their propose approach minimises the distortion to price signals, as required to comply with the Rules.[191]

We also require that the Queensland distributors to consider the approach taken by other distributors, such as Essential Energy. We expect the Queensland distributors to work constructively with their stakeholders to develop this element of their revised tariff structure statement.

[190] AER, *Attachment 18,* Tariff structure *statement, Draft decision - Essential Energy distribution determination 2019–24*, April 2019, p. 18-13.

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

A Retail and network characteristics of relevance to tariff reform in Queensland

Purpose

Electricity distributors are required to develop their network tariff strategies against a backdrop of a unique set of environmental conditions. Some of these conditions will constrain the reform of network tariffs whilst other conditions will enable more reform to occur than otherwise the case.

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

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

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

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

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

Key characteristics of Energex and Ergon Energy's electricity networks

Energex supplies network services to 1 463494 households and businesses in the growing region of South East Queensland, comprising a population base of around 3.4 million people. [192]

Ergon Energy has the largest network area of any distributor of electricity in the NEM, supplying network services to 752909 homes and businesses in Queensland across around a network spanning 1.7 million square kilometres.[193]

The Queensland and South Australia are at the forefront of the customer led and technology driven transformation of the energy sector. Queensland has the highest number of roof top solar PV installations in Australia. The Queensland distributors are forecasting the solar PV installation to reach almost a million installations by the end of the 2020–25 regulatory control period. They also predict the take-up of batteries and electric vehicles to accelerate over the medium to long term, albeit from a low base. The growing penetration of Distribution Energy Resources, such as roof top solar PV, in changing the way that customers are using the electricity distribution network. It is clear that existing legacy flat tariffs do not provide appropriate signals to these customers. This has created a strong long-term rationale for the Queensland distributors to introduce more cost reflective tariffs.

The historical over-investment in network capacity has resulted in a marked deterioration in the capacity utilisation rate in Queensland. The presence of excess capacity, together with minimal growth in peak demand in the foreseeable future, has resulted in growth-related capital expenditure no longer being a major driver of network costs. It also means that the Queensland distributors are able to adopt a considered approach to the introduction of more cost reflective tariffs given that there will be little, if any, economic consequences for doing so. This approach will also ensure that residential customers will have adequate time to become familiar with more complex pricing concepts such as kW demand and time of use charging windows. Delaying the introduction of more complex forms of cost reflective pricing, such as capacity tariffs, will ensure that the Queensland distributor can engage more constructively with its stakeholders on how best to structure this tariff. We encourage the Queensland distributors to under a pricing trial during the 2020–25 regulatory control period to test different design options for the capacity tariff and gather a more robust evidence and knowledge base on customer acceptance and response to this more innovative pricing approach.

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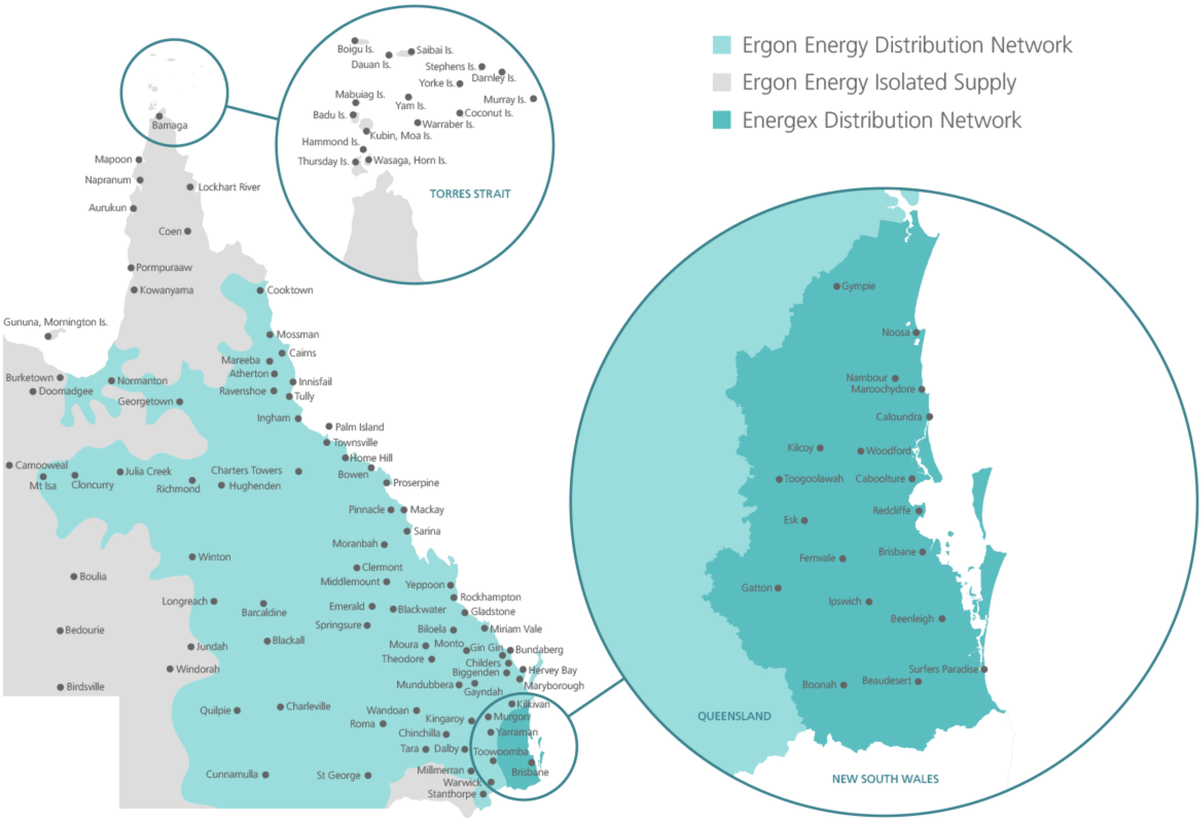
192 Energex, *Regulatory Proposal* - Energex *distribution determination - 2020–25 Regulatory Control Period*, January 2019, p. 2.

193 Ergon Energy, *Regulatory Proposal - Energex distribution determination - 2020–25* Regulatory Control Period, January 2019, p. 2.

The geographic footprint of the network areas of Energex and Ergon Energy are shown in Map A.1 below.

Map A.1 Network areas of the Queensland Distributors



Source: Ergon Energy.

Maximum Demand Growth

The Energex and Ergon Energy networks have different characteristics which reflect the different geographic environments in which the networks operate. The Ergon Energy network has lower customer numbers overall, with lower customer density, whilst the Energex network is largely metropolitan. Nevertheless, temperature, economic growth and electricity prices are the main drivers of system maximum demand in both electricity networks.[194]

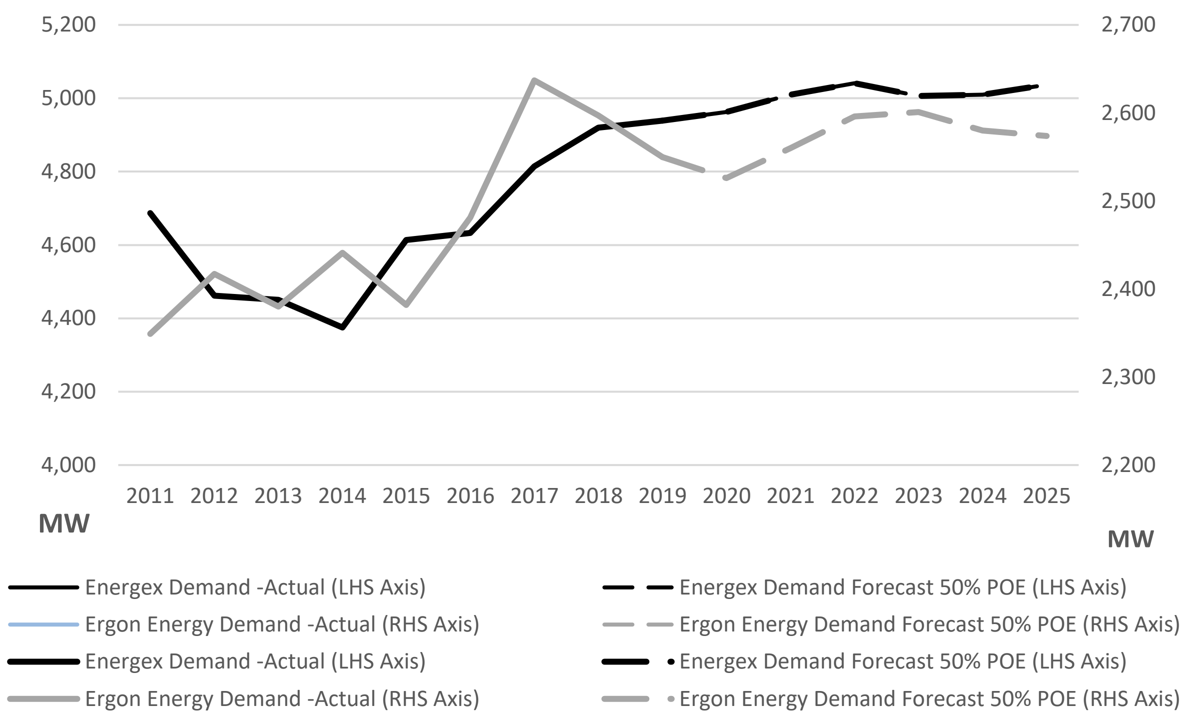
The Queensland distributors are forecasting modest growth in peak demand over the medium term with annual growth in system-wide peak demand over the 2020–25 regulatory

194 ACIL, *Review of System Maximum Demand and Energy, Report to Energy Queensland*, May 2018.

control period forecast to average around 0.29 per cent for Energex[195] and 0.38 per cent for Ergon Energy.[196]

The figure below provides a comparison of the Queensland distributor's forecast and historical weather corrected system-wide peak demand at the 50 per cent Probability of Exceedance.

Figure A.1 Forecast of QLD distributor's peak demand in next regulatory control period



Source: Ergon Energy, Energex.

The Queensland distributors forecast of moderate growth in system-wide peak demand over the next five years is consistent with the AEMO's prediction of weak growth in peak summer demand in Queensland and the other NEM regions over the next few years. Interestingly, AEMO is long-term forecast is for peak demand to grow across all NEM regions, see table below.

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195 Energex, *Regulatory Proposal 2020–25*, January 2019, p. 38.

196 Ergon Energy, *Regulatory Proposal 2020–25*, January 2019, p. 35.

Table A.1 Forecast of maximum demand by NEM region – 50 per cent POE

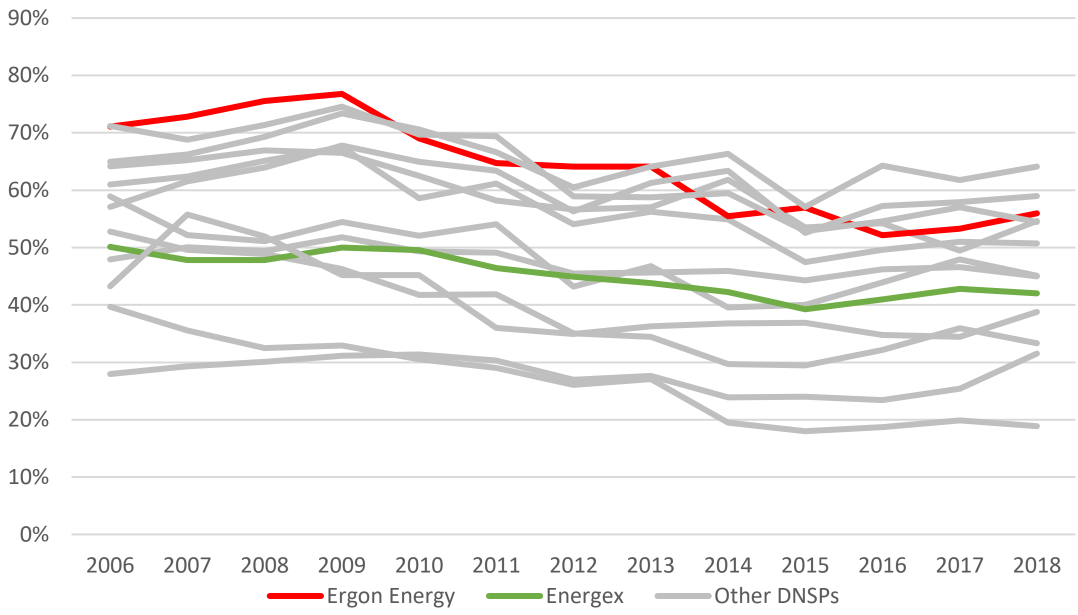
NEM region	Season	2019	2023	2027	2037
New South Wales	Summer	12,366	12,442	13,172	14,870
	Winter	11,820	12,073	12,970	15,628
Queensland	Summer	8,533	8,626	8,857	9,853
	Winter	7,375	7,855	8,242	9,427
Victoria	Summer	8,983	9,249	9,679	11,371
	Winter	7,573	7,861	8,323	10,378
South Australia	Summer	2,901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

Source: AEMO.

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

Figure A.2 provides a comparison of the historical trend in annual network utilisation for Energex, Ergon Energy and the other distributors in the national electricity market.

Figure A.2 Historical trends in network capacity utilisation by distributor



Source: AER analysis.

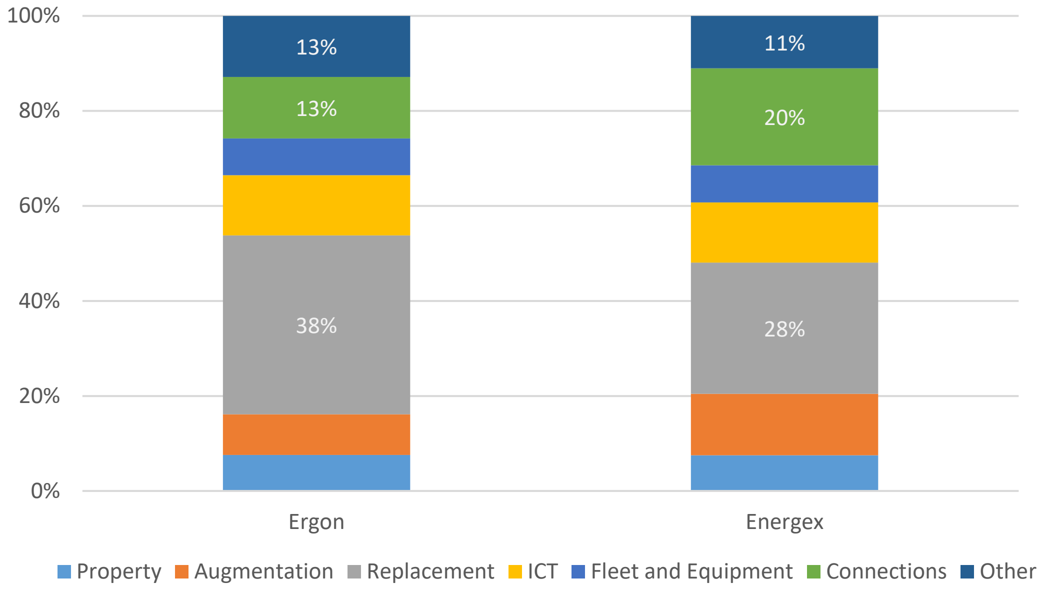
It is clear from the above figure that the Queensland distributors have experienced significant decline in network capacity utilisation over the past decade, reflecting the combined influence of historical over-investment in new capacity.[197] The widespread presence of idle capacity has resulted in peak demand growth no longer being a major driver of future network costs in QLD. This will impact the level and composition of future capital expenditures, as discussed in the section below.

Network Capital Expenditure

As highlighted in Figure A.3 below, replacement is the largest component of the proposed capital expenditure of the Queensland distributors for the next regulatory control period, accounting for 38 per cent and 28 per cent of the total capital expenditure requirement of Ergon Energy and Energex, respectively. Interestingly, connections is also expected to be a major driver of future capital expenditure for Energex, accounting for around 20 per cent of the total capital expenditure requirement. This importance reflects the forecast growth in new connections, particularly in South East Queensland. Connections will account for around 13 peer cent of the future capital expenditure requirement for Ergon Energy. Fleet and equipment will also be a material driver of future capital expenditure in QLD.

197 ACCC, *Retail Electricity Price Inquiry - Final Report*, June 2018, pp. 1633-165, Section 7.2.2.

Figure A.3 QLD distributors' proposed capital expenditure by category - 2020–25 Regulatory Control Period



Source: Ergon Energy; Energex.

The relatively high importance of replacement capital expenditure in the cost function of most distributors in Australia has implications for the design of cost reflective network tariffs, particularly in terms of the level and structure of the peak charging parameter. The challenges associated with the design of cost reflective tariffs in an environment of excess network capacity and minimal growth in peak demand is explored in appendix B of this attachment.

Energy Consumption

The Energex and Ergon Energy are forecasting that total energy consumption to grow modestly at an annual rate of less than 1 per cent, respectively over the next regulatory control period. This is consistent with the AEMO operational energy consumption forecast under its neutral scenario which predicts that grid supplied energy consumption across the NEM will remain flat as a result of forecast strong growth in roof top solar PV projected to offset forecast growth from expected increases in population and economic activity.[198] Energy consumption in this context is measured net of the generation output from roof top solar PV.

The underlying composition of energy consumption by major customer segment is changing over time, reflecting the influence of energy conservation, uptake of energy efficient

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

appliances and new energy technologies, price response and changes in the underlying structure of the economy away from energy-intensive sectors such as manufacturing.

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

Table A.2 Solar PV system installations by jurisdiction

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

Source: Clean Energy Regulator.

The general growth in solar PV installations over the past decade reflects the falling real price of these systems, the incentives under existing energy-based electricity tariff structures and the influence of government incentives. Energy-based electricity tariff structures encourage the reduction in total consumption supplier by the grid, rather than reducing consumption or shifting consumption away from peak times.

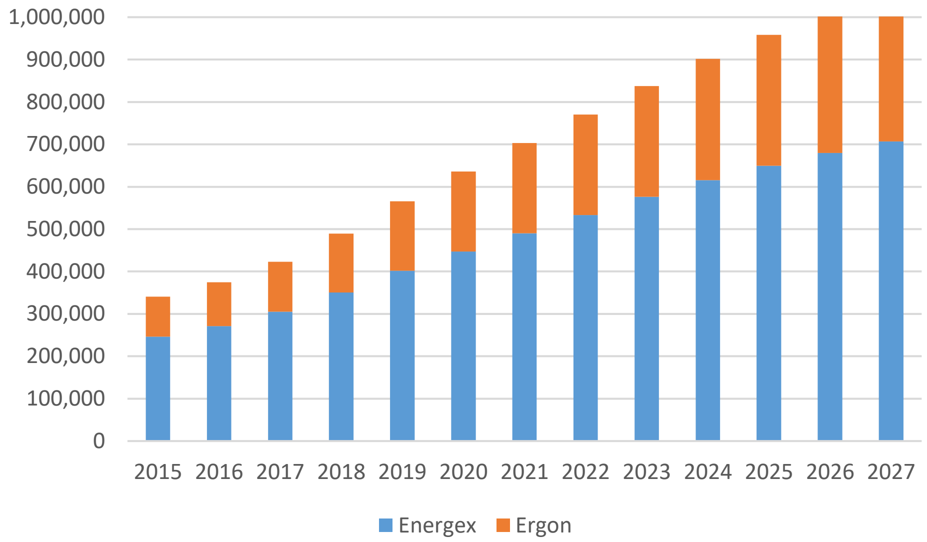
The highest number of solar PV system installations have been recorded in Queensland, New South Wales, Victoria and South Australia.

Figure A.4 shows a comparison of the historical and forecast number of solar PV systems installed by Queensland distributor. It is clear that Energex currently accounts for around two thirds of the total solar PV systems in Queensland. This share is forecast to increase over the next five years with Energex expected to account for around three quarters of all solar PV systems in Queensland by 2024–25, reflecting expectations of relatively strong uptake in South East Queensland.

It is also relevant to note that the number of batteries installed in Queensland is expected to also rise substantially over the next five years, albeit from a very low base. The QLD distributors forecast that the number of batteries installed will rise to around 80000 by 2024–

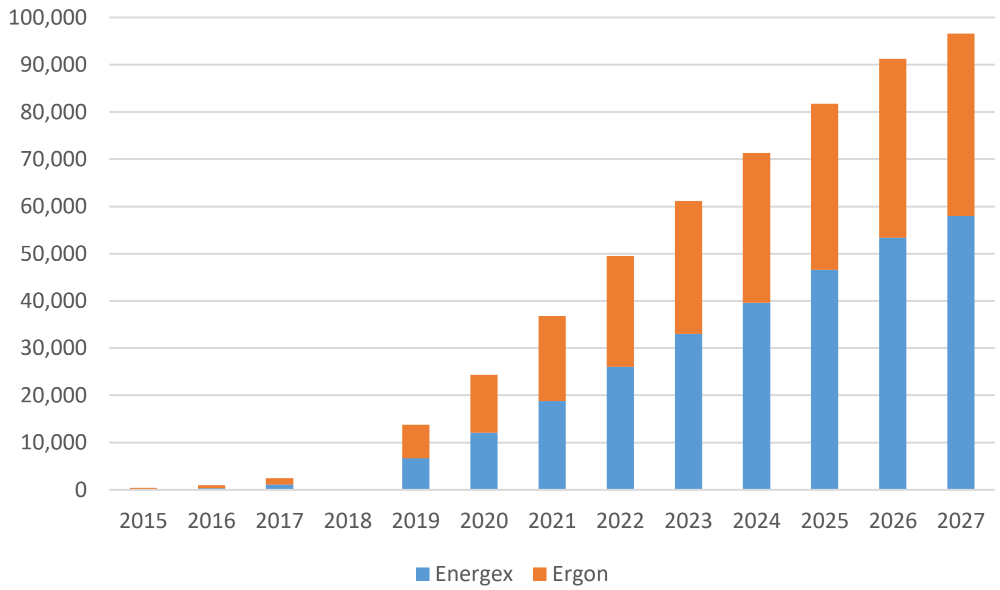
25, with the number of installations evenly spread over both the Energex and Ergon Energy network areas, see Figure A.5. Similarly, the Queensland distributors forecast that the number of electric vehicles (EVs) will rise substantially over the next five years, also from a very low base currently, see Figure A.6.

Figure A.4 Number of roof top solar PV installations by QLD distributor



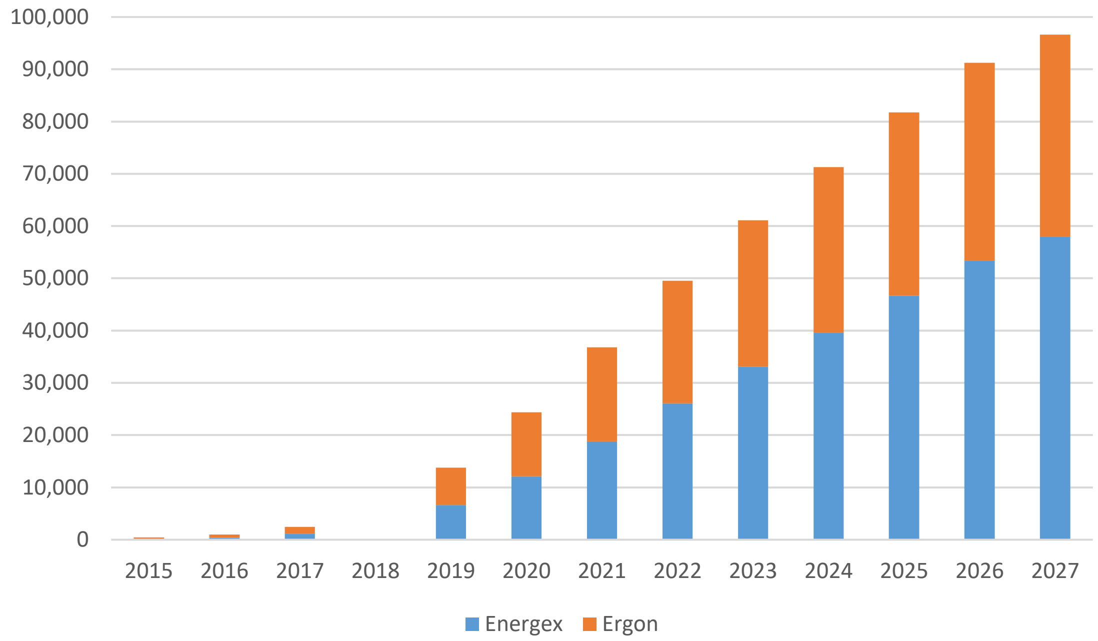
Source: Energy Queensland.

Figure A.5 Number of battery installations by QLD distributor



Source: Energy Queensland.

Figure A.6 Number of electric vehicles by QLD distributor



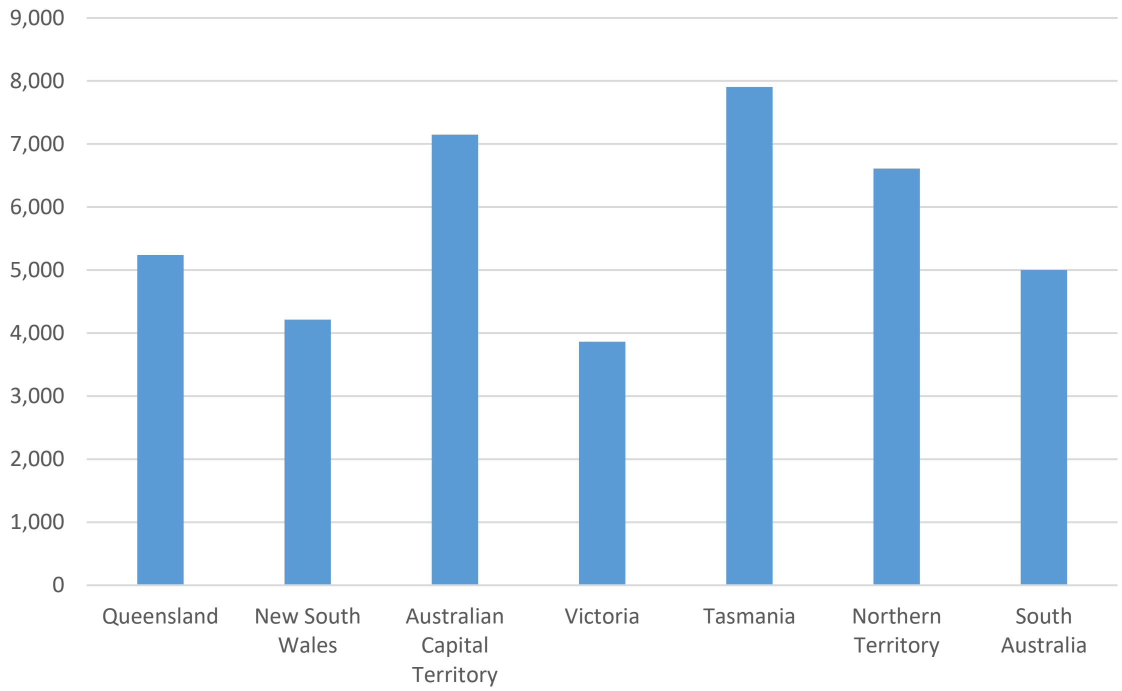
Source: Energy Queensland.

Energy Consumption per residential customer

Figure A.7 highlights the differences in annual electricity consumption for a representative residential customer by jurisdiction.[199]

[199] AEMC, *Electricity Price Trends*, December 2018.

Figure A.7 Current annual electricity consumption per household by NEM region



Source: AEMC.

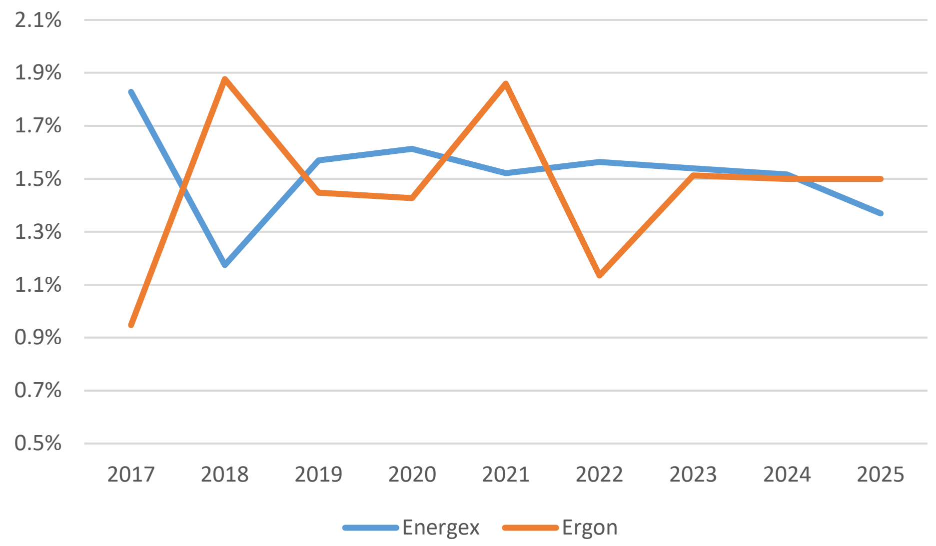
This variation reflects regional differences in temperature conditions, the mix of appliances and the market penetration of gas for heating and cooking. The influence of colder temperatures have resulted in Tasmania and the Australian Capital Territory having the highest annual residential electricity consumption in the national electricity market. Whereas Victoria and New South Wales have the lowest annual residential electricity consumption in the NEM, in part reflecting the higher penetration of gas for heating and cooking. We note that annual electricity consumption per residential customer is similar in South Australia and Queensland.

As with most regions in the NEM, average energy consumption per residential customer is expected to decline over the over the next regulatory control period. The key underlying driver of this trend is expected to be the continued increase in the penetration of solar PV under a net metering arrangement.

Customer numbers

Figure A.8 shows that the Queensland distributors are forecasting that the total number of customers connected to their electricity distribution networks to grow steadily over the next regulatory control period, reflecting the projected growth in population.

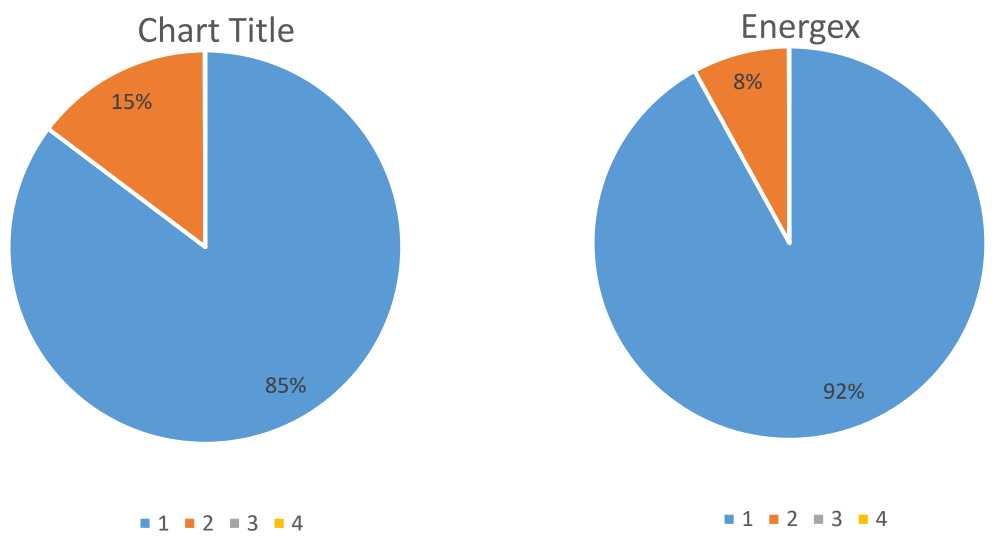
Figure A.8 Annual growth rate in total connections by QLD distributor



Source: AER analysis.

As with the other electricity distributors in the national electricity market, residential customers account for a high proportion of the total customer base of the Queensland distributors, as shown in Figure A.9 below.

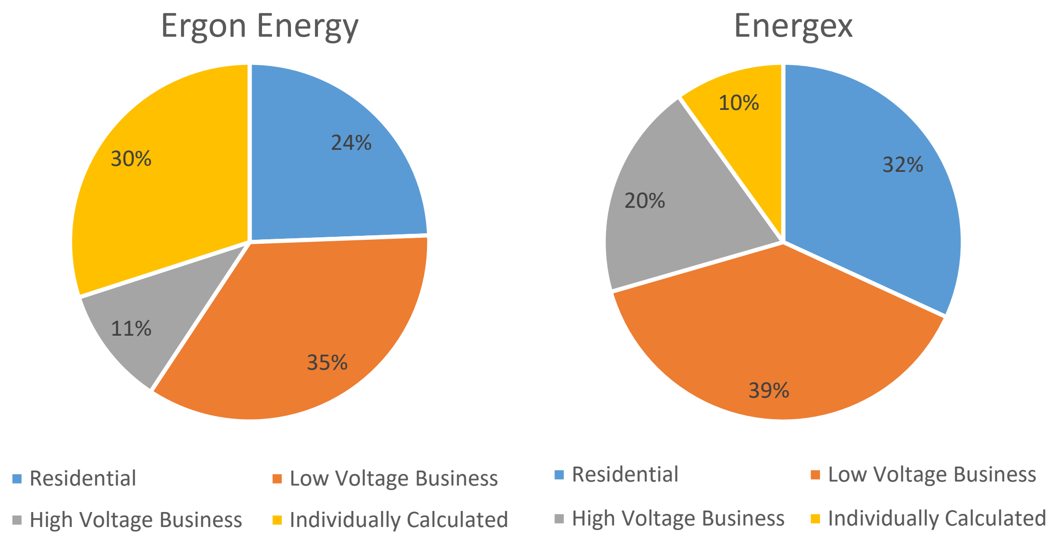
Figure A.9 Current number of customer by tariff segment – QLD distributors



Source: AER analysis.

While business customers connected at the higher voltage levels of the electricity network account for less than one percent of all customers, the large size of these customers means that they account for a material share of Energex and Ergon Energy's total energy consumption per annum, as shown in figure below.

Figure A.10 Current annual energy consumption by tariff segment – QLD distributors



Source: AER analysis.

Network costs, revenues and average network prices

The magnitude of the expected change in the annual revenue requirement is a key determinant of the pace of network tariff reform. This is because the extent that network tariffs can be reformed over time is constrained by the customer impact principle in the NER.[200] It should also be noted that it is easier to gain overall customer acceptance of cost reflective pricing if the majority of customers are likely to pay less during the period that tariffs are being transitioned to cost reflectivity.

Standard control distribution revenue

Energex and Ergon Energy both proposed a P-nought reduction in their proposed distribution revenue requirement for the provision of standard control distribution services in the first year of the next regulatory control period. Our draft decision has resulted in an increase in the reduction in the standard control distribution revenue requirement in 2020–21, as shown in the table below.

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

Table A.3 Ergon Energy proposed standard control revenue requirement

Smoothed Distribution Revenue Requirement	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25
Ergon Energy - proposed ($m)	1293.4	1241.6	1271.6	1302.4	1333.9	1366.2
Ergon Energy - draft decision ($m)	1293.4	1102.2	1129.2	1156.9	1185.2	1214.3
Energex proposed ($m)	1362.4	1246.4	1276.6	1307.5	1339.1	1371.5
Energex - draft decision ($m)	1362.4	1112.2	1139.4	1167.3	1195.9	1225.2

Source: AER analysis.

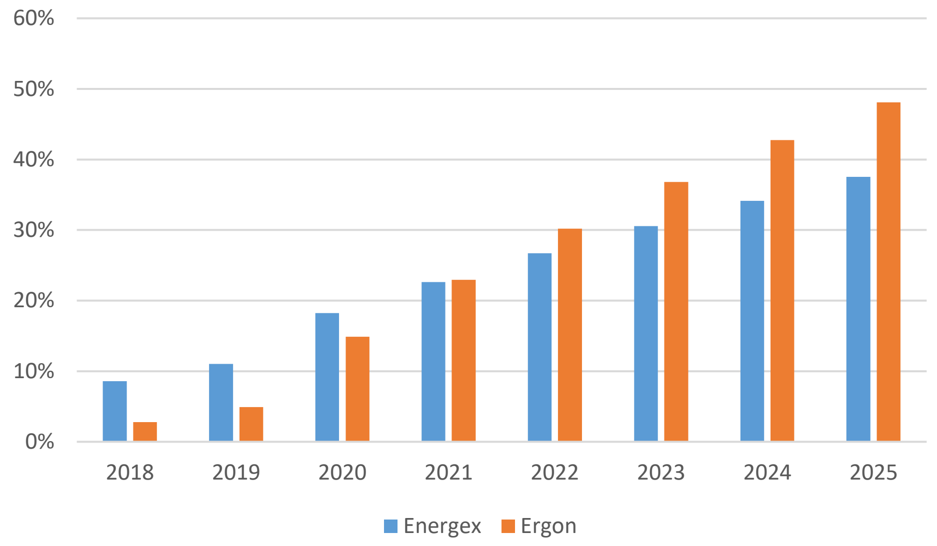
The reduction in the distribution revenue requirement will support the tariff reform process to the extent that it has a moderating influence on the customer impact of the introducing more cost reflective tariff structures.

Interval metering

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

Figure A.11 shows that the QLD distributors expect to have significant penetration of smart metering in the residential customer segment by the end of the next regulatory control period.

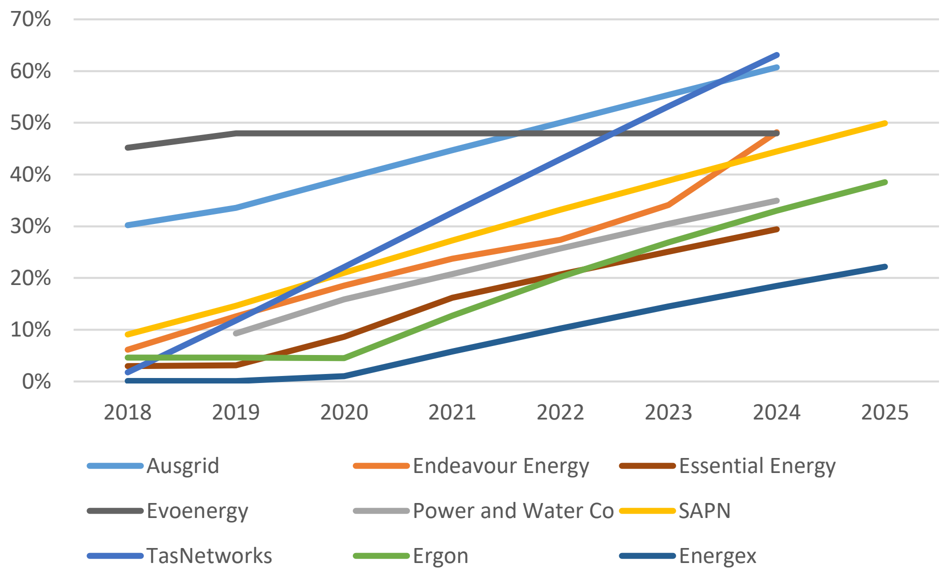
Figure A.11 Smart meter penetration in residential customer segment by QLD distributor



Source: Queensland distributors.

Figure A.12 shows that the QLD distributors expect to have a similar penetration of smart metering in the residential customer segment in the medium term to other electricity distributors in the national electricity market.

Figure A.12 Smart Meter penetration in residential customer segment by electricity distributor



Source: AER analysis.

It is interesting to note that by the end of this financial year, the Queensland distributors are forecasting that the penetration of smart metering in the residential customer segment for Ergon and Energex will reach a significant 15per cent and 18per cent, respectively. This expectation reflects the installation of smart metering on a new and replacement basis, as required to comply with the new metering provisions in the NER.[201] It also reflects the impact of the strong uptake of solar PV in QLD, which require that the customers upgrade their metering in order to connect a solar PV system to the electricity network.

Proposed procedures for tariff assignment and reassignment

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

The key elements of the Queensland distributor's proposed tariff assignment and re-assignment procedure are summarised below:

- To assign all new residential and small business customers that connect to the electricity distribution from 1 July 2020 to the applicable demand tariff with the option to opt-in to the proposed Inclining Block Tariff.
- Existing residential and small business customers that replace or upgrade their basic accumulation meter from 1 July 2020 will be re-assigned to the demand tariff with the option to opt-in to the Inclining Block Tariff.

The QLD distributors have also proposed the following measures to mitigate the impact of the introduction of more cost reflective network pricing, as summarised below:

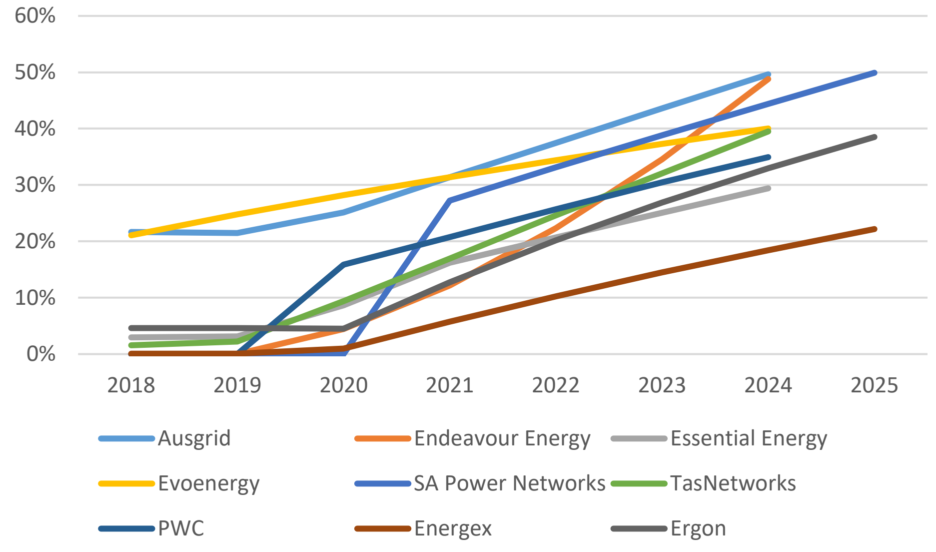
- Existing residential and small business customers on the flat tariff that have a smart meter installed in their premise as at 30 June 2020 will be allowed to remain on the proposed Inclining Block Tariff. These customers have the option to opt-in to the applicable demand tariff.
- Hardship residential and small business customers are allowed to opt-in to the legacy flat tariff.
- Retail transitional tariff customers in Ergon Energy's network area are allowed to opt-in to an applicable Time of Use energy tariff.

The above proposed tariff assignment and reassignment procedure is expected to result in increased penetration of cost reflective network pricing in Queensland. Nevertheless, the Queensland distributor's proposal is to allow existing customers with smart metering installed as at 30 June 2020 to remain on the flat tariff will mean that the penetration of cost

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

reflective pricing in the residential customer segment will lag other distributors, as shown in the figure below.

Figure A.13 Annual penetration of cost reflective network pricing in residential customer segment by QLD electricity distributor



Source: AER analysis.

The figure above highlights that Evoenergy, Ausgrid, Endeavour Energy and SA Power Networks are expected to achieve the highest penetration of cost reflective pricing, whereas the QLD distributors, particularly Energex, will lag the progress being made in other jurisdictions. This is an outcome of the Queensland distributor's proposal in their updated tariff structure statement to re-assign existing customers with smart metering as at 30 June 2020 to the proposed inclining block tariff, rather than a more cost reflective tariff. We do not consider this element of their TSS proposal to contribute to compliance with the pricing principles in the Rules. We required that the Queensland distributors reassign these customers to a cost reflective tariff, noting that we also required that they also ensure that they carefully manage the impact of introducing cost reflective pricing to customers by adopting a range of customer impact mitigation measures, for more detail on this aspect of our draft decision refer to the main body of this attachment.

Tariff classes

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

The following table provides a summary of the current tariff classes for each electricity distributors.

It is clear from this analysis that there is a considerable variation in the extent of tariff class disaggregation across electricity distributors, particularly in respect to customers connected at the low voltage level of the electricity network.

Table A.4 Comparison of tariff classes by selected electricity distributor

Connection characteristic	SA Power Networks	Energex and Ergon Energy	Ausgrid	Endeavour Energy	Essential Energy	TasNetworks	Evoenergy	Power and Water
Low voltage (230/400 V)	• Residential • Small business < 160 MWh pa • Large business > 160 MWh pa	• Standard Asset Customers	• Low Voltage	• Low Voltage Energy • Low Voltage Demand	• Low Voltage Energy • Low Voltage Demand	• Residential • Small Low Voltage • Large Low Voltage • Uncontrolled Energy • Controlled Energy • Irrigation	• Residential • Commercial Low Voltage	• < 750 MWh per annum • > 750 MWh per annum
High Voltage (11 or 22 kV)	• High Voltage	• Connection Asset	• High Voltage	• High Voltage	• High Voltage	• High Voltage	• High Voltage	• High Voltage
Sub-transmission Voltage (33, 66 or 132 kV)	• Sub-transmission Voltage	• Individually Calculated Tariff	• Sub-transmission Voltage • Transmission connected	• Sub-transmission Voltage • Inter-Distributor Transfer	• Sub-transmission Voltage	• Individually Calculated Tariff		
Unmetered Supply			• Unmetered	• Unmetered	• Unmetered	• Unmetered		

Source: AER analysis.

Network use of system tariffs

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

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

Overview of current network tariffs

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

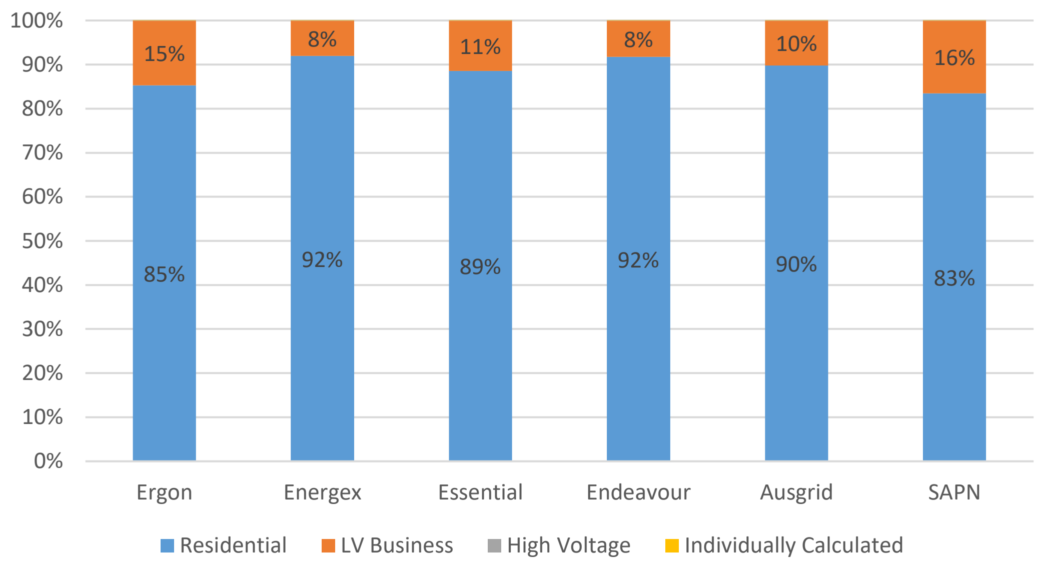
- It is common for residential and small business customers with accumulation metering to be assigned to a flat network tariff comprising a fixed charge and a flat energy charge. The only exceptions are Ergon Energy and Endeavour Energy that currently have inclining block tariff structures currently in place.
- A time of use energy tariff is commonly available for residential and small business customers with interval metering. These tariffs typically comprise a fixed charge and peak, shoulder and off-peak energy charges. The peak times vary considerably across electricity distributors, reflecting in part differences in load profiles.
- Electricity distributors are also introducing demand tariffs to residential and small business customers with smart metering installed. These tariffs typically comprise a fixed charge, a peak demand charge and an anytime energy charge.[202] As with the time of use tariffs, the peak times applying to the demand charge vary considerably across electricity distributors.

The following figure shows that residential customers account for between 83 per cent and 92 per cent of all customers served by electricity distributors. The second highest share is low voltage connected business customers, which account for between 8 per cent and 16 per cent of total distribution customers. High voltage customers account

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

for typically less than 1 per cent of all distribution customers. There are also a small number of very large customers connected to either the high voltage or sub-transmission voltage level of the electricity network that are assigned to a site-specific individually calculated tariff. These tariffs are more cost reflective than the tariffs for small customers both in terms of structure and price levels.[203] Interestingly Ergon Energy currently has around 80 customers or individual connection points assigned to site-specific individually calculated tariffs. This compares to other electricity distributors that typically have less than 50 customers on these more bespoke network tariffs, reflecting the increased complexity and higher transaction costs associated with developing and maintaining these types of network tariffs.

Figure A.14 Current share of customers by tariff grouping by selected electricity distributor



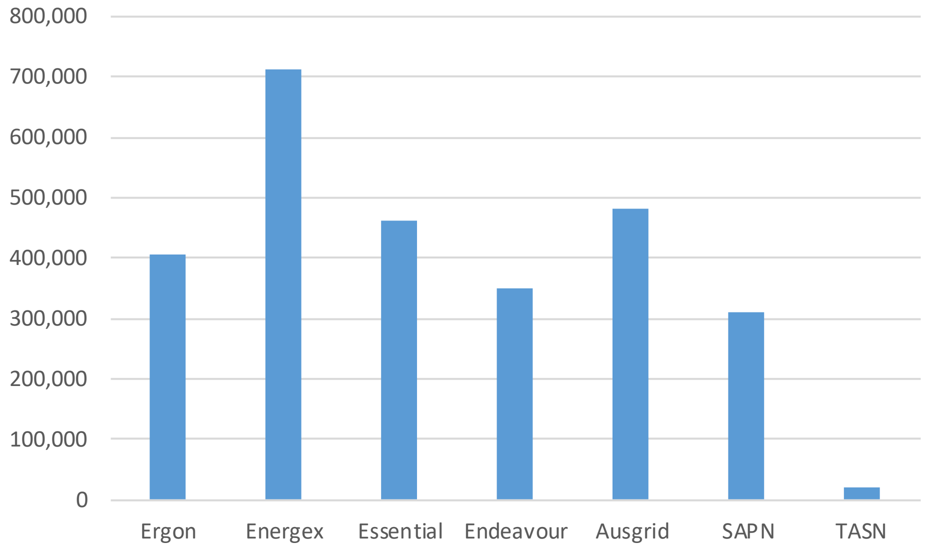
Source: AER analysis.

Electricity distributors also offer controlled load tariffs. Unlike primary network tariffs, controlled load tariffs require that the customer allow the electricity distributor to interrupt or restrict the supply of energy to the customer's connection point. The Queensland distributors are leading the industry in terms to the design and uptake of controlled load tariffs, as highlighted in the figure below that shows Energex currently has a significantly higher number of customers on controlled load tariffs compared to the other distributors in the NEM. This reflects the important role played by controlled load in Queensland from a demand management perspective. It is relevant to note that the Queensland distributors propose to expand their suite of load controlled tariffs by

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

introducing new load controlled tariffs in the business customer segment in the 2020–25 regulatory control period

Figure A.15 Current number of customers on network controlled load tariffs by selected electricity distributor

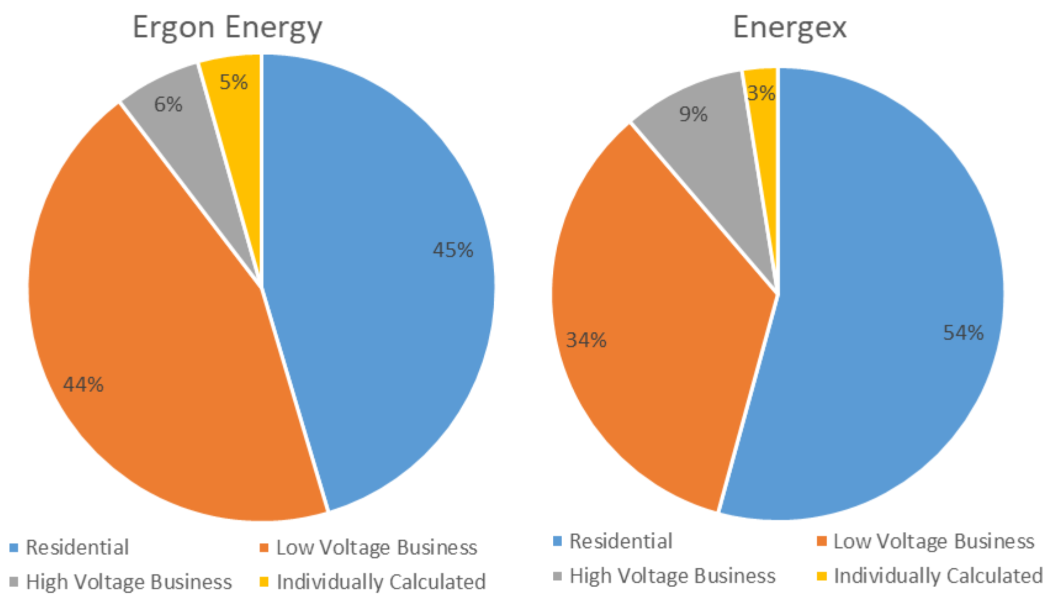


Source: AER analysis.

The QLD distributors’ network use of system tariffs

The following figure provides a comparison of the forecast distribution use of system revenue share by charging parameter type for Ergon Energy and Energex in 2019–20.

Figure A.16 QLD Distributors’ DUOS revenue share by charging parameter



Source: AER analysis.

The figure above highlights that Ergon Energy recovers a significant proportion of its Distribution revenue requirement from the low voltage business customer segment compared to Energex.

The appropriateness of the proposed pace of network tariff reform must be assessed in the context of the customer impact principle in Chapter 6 of the Rules.[204] In this regard, we note that the AER draft decision results in a material reduction in the distribution revenue requirement in the 2020–21. This revenue reduction will contribute to a more supportive environment for the introduction tariff reform to the extent that it has a moderating influence on bill impacts.

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

From a regulatory compliance perspective, the AER is focused on whether the network pricing approach set out in Ergon Energy's tariff structure statement proposal will contribute to the achievement of the Network Pricing Objective in Chapter 6 of the Rules.[205] Compliance with the distribution pricing principles in the Rules requires that the electricity distributor make progress towards long run marginal cost-based pricing and the efficient recovery of residual costs. These issues are explored below:

Progress towards efficient recovery of residual costs

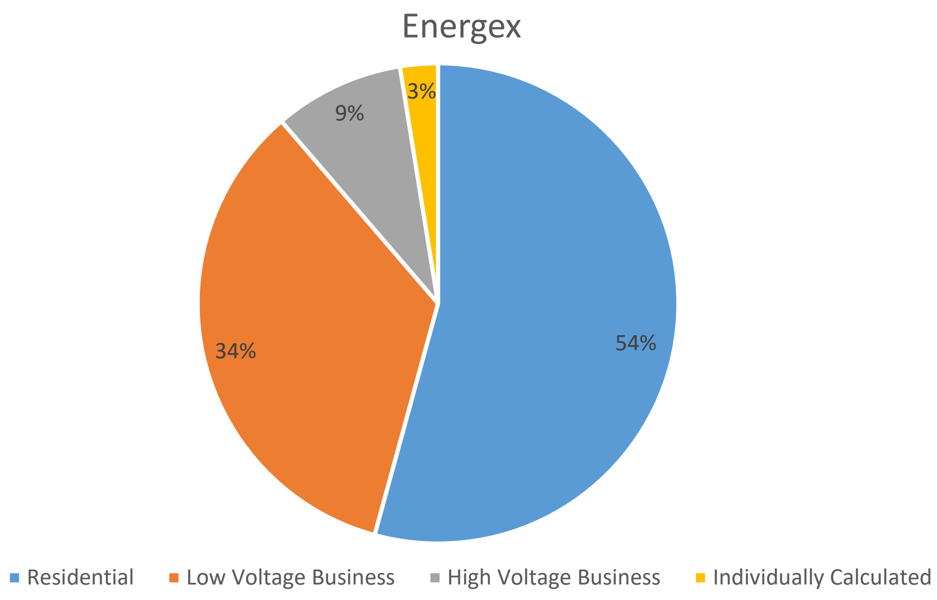
The efficient recovery of residual costs requires that these costs are recovered from network customers in a manner that minimises the distortion to efficient network usage. The fixed charge has the potential to be an economically efficient way to recover residual costs because changes in the level of the fixed charge typically do not influence the investment, network connection and consumption decisions of electricity distribution customers. Nevertheless it is important from a compliance perspective that the rate of fixed charge increase does not contravene the customer impact principle in the Rules.[206]

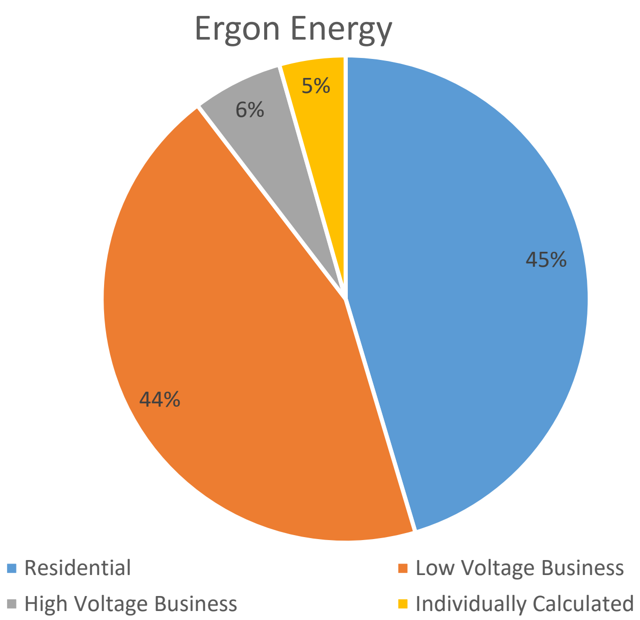
[204] NER, cl. 6.18.5(h).

[205] NER, cl. 6.18.5(d).

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

Figure A.17 Current DUoS revenue share by charging parameter by QLD distributor



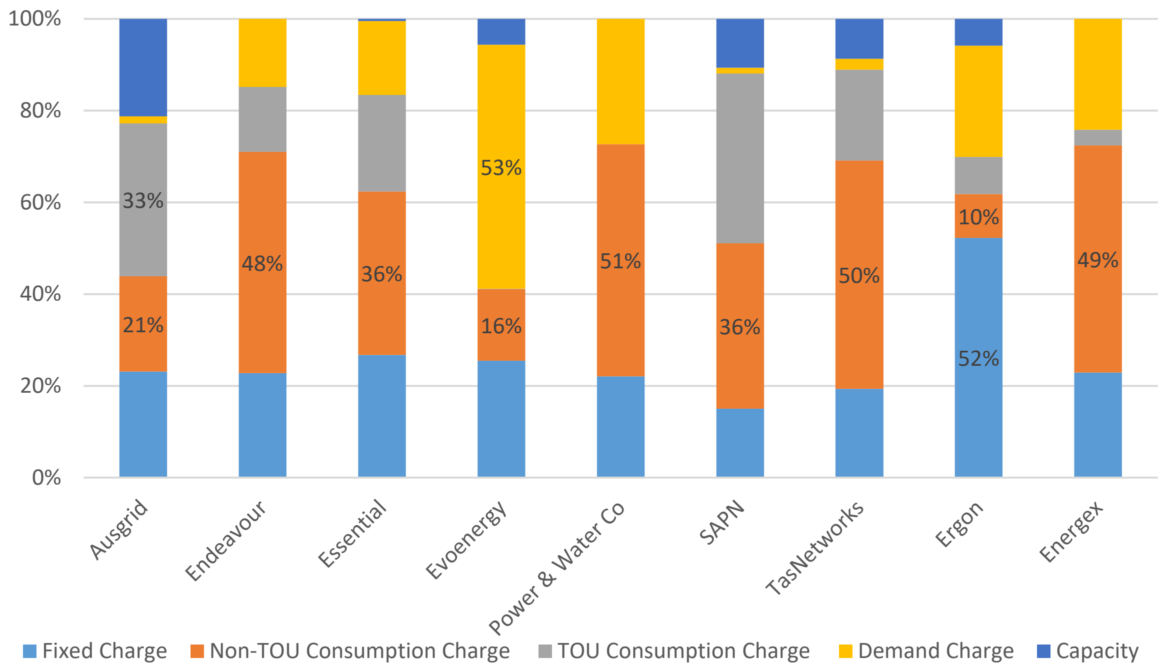


Source: AER analysis.

The key highlight from the figure above is that Ergon Energy has a much higher reliance than Energex on the fixed charge from a revenue recovery perspective. Ergon Energy has been able to apply relatively high fixed charges in the residential and small business customer segment without contravening the customer impact principle in the Rules due to the moderating influence of the QLD Government's uniform tariff policy and the regulated retail pricing arrangements implemented by the Queensland

Competition Authority. For example, the fixed charge for Ergon Energy's residential Inclining Block Tariff for East Zone and TUoS Region 1 is currently $1.25 per day. This is significantly higher than the comparable fixed charge at the regulated retail level. More information about this issue is available in the Queensland Competition Authority's final determination for retail regulated prices in regional Queensland for the 2019–20 financial year.[207]

Figure A.18 Current network revenue share by charging parameter by selected electricity distributor



Source: AER analysis.

The figure above shows that the current reliance on anytime energy charges from a NUoS revenue perspective varies markedly across individual electricity distributors. Power and Water Corporation and Endeavour Energy are estimated to have the highest reliance on anytime energy charges, whereas Ergon Energy will have the lowest reliance in line with their relatively high fixed charges in the residential and small business customer segment.

We note that the Queensland distributors are not proposing to materially rebalance their tariffs away from inefficient energy charges towards more efficient fixed charges, except where this re-balancing arises as a result of the increasing penetration of cost reflective pricing.

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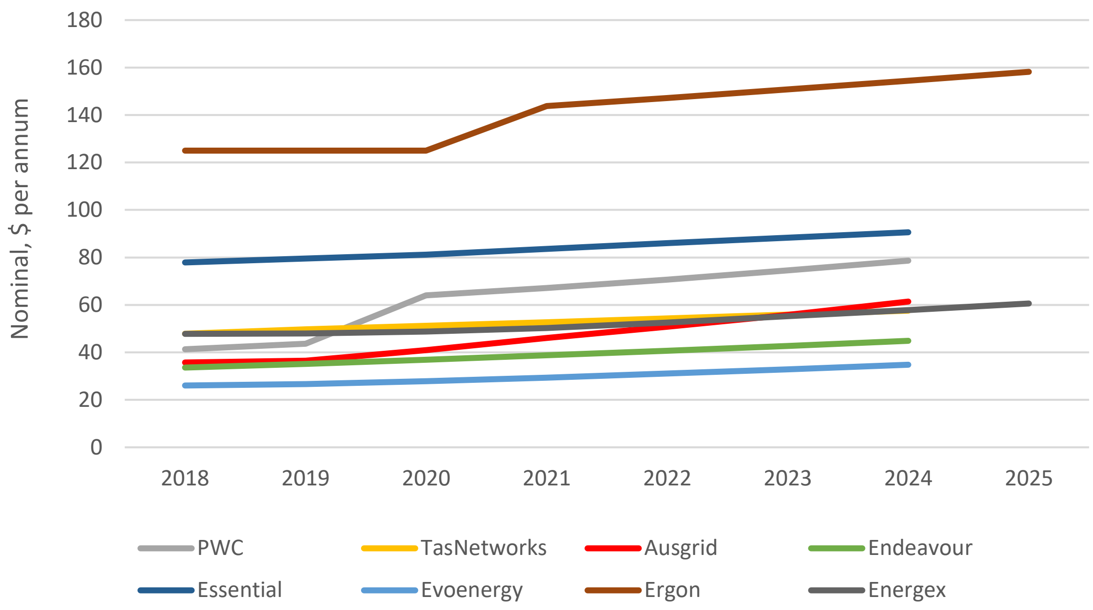
[207] QCA, *Regulated Retail Electricity Prices for 2019-20*, May 2019, pp. 104-107.

On the basis of the indicative pricing schedule accompanying the updated TSS proposal, the Queensland distributors propose to increase fixed charges for the residential flat tariff by around 2 to 3per cent per annum in the next regulatory control period. The AER notes that this is similar to the fixed charge increases expected in other jurisdictions, as shown in the figure below.

The figure below provides insights into the extent that the electricity distributors with open regulatory determinations propose to increase the level of the fixed charge of their residential anytime energy network tariff over the next five years.

Figure A.19 Residential fixed charges by selected electricity distributor



Source: AER analysis.

Progress towards long run marginal cost price signals

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

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

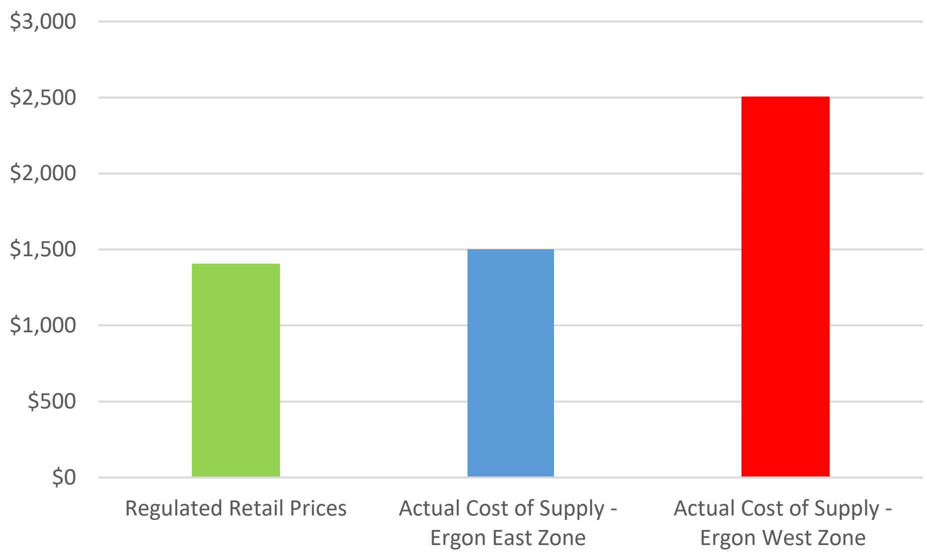
Electricity distributors expect to see a material increase in the penetration of interval metering over the next five years. This will enable these electricity distributors to potentially achieve a substantial increase in the percentage of residential customers assigned to a cost reflective tariff at the network level.

Retail electricity pricing in QLD

The electricity market in Queensland is complex with customers in Ergon Energy's network area subject to retail price regulation, whereas customers in Energex's network area are able choose their retailer for their electricity and gas requirements. It is also complicated by the Queensland Government Uniform Tariff Policy that requires, wherever possible, that customers in Ergon Energy's network area pay no more for their electricity, regardless of their geographic location.[208] In other words, regulated retail electricity tariffs for Ergon Energy's residential and small business customers will be based on the costs of supplying electricity in South East Queensland,[209] and the regulated retail electricity tariffs for large business customers will be based on the lowest costs of supply in regional Queensland.[210]

The Uniform Tariff Policy generally results in regional residential, small business and some large business customers paying electricity retail tariffs that are lower than the actual cost of supplying electricity to these customers, as illustrated in the figure below. The shortfall is made up via a subsidy paid by the Queensland Government, which is estimated to be around $465 million in 2018–19.[211]

Figure A.20 Illustration of subsidy under regulated retail tariffs in QLD



Source: QCA.

[208] QCA, *Regulated Retail Electricity Prices for 2019-20*, May 2019, Appendix A.

[209] Energex distribution network area.

[210] East pricing zone of Ergon Energy's distribution network area and Transmission Region One.

[211] QCA, *Regulated Retail Electricity Prices for 2019-20*, May 2019, p. iii.

Transitional retail electricity tariffs

In 2012, the government made a policy decision to move to electricity tariffs that support cost-reflective tariffs and encourage more efficient use of electricity.

Given that some customers had made investment and business decisions based on the historical non-cost-reflective price structures and subsidy levels, the Queensland Competition Authority (QCA) put in place transitional measures. The QCA decided to retain some of these non-cost-reflective tariffs for a transitional period to allow customers up to seven years to recoup some value from their existing investments and adjust their business practices to suit the tariff structures, and subsidy levels, of standard business tariffs.

Some business customers, including farmers and irrigators, continue to be supplied under transitional or obsolete tariffs. As discussed above, these legacy retail tariffs do not reflect the underlying costs of supply and cannot be determined under a Network component + Retail component approach.

The analysis undertaken by the QCA in their recent review of regulated retail electricity prices indicates that many customers on transitional electricity tariff will pay less under standard retail electricity tariffs. Nevertheless, this analysis revealed that some of these customers could receive a material retail bill increase as a consequence of being reassigned to a standard retail electricity tariff.[212]

The Queensland Government recently decided to delay the expiration of the transitional retail tariffs by a year to 30 June 2021.[213]

Regulated Retail tariffs in Ergon distribution network area

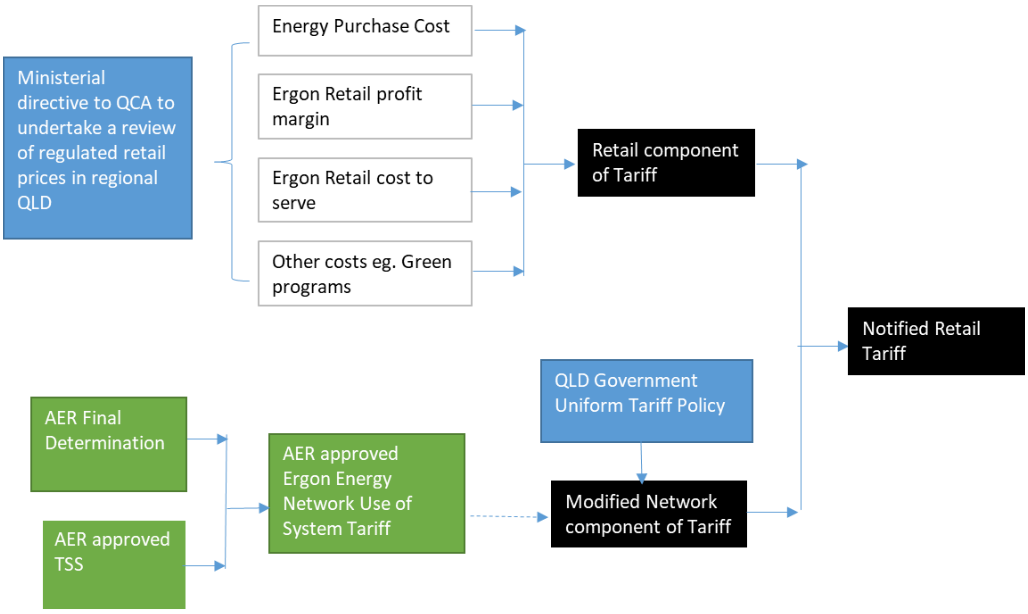
Retail price regulation results in a complicated interaction between Ergon Energy's network prices and tariff structures, which are approved by the AER, and the retail tariffs actually paid by end-customers.

The underlying role played by the AER approved network tariffs in the current QCA framework for setting regulated retail prices is represented in the figure below:

[212] QCA, *Final determination - Regulated retail electricity prices for 2019–20*, May 2019, pp. 108-115. This report is available from the following link: www.qca.org.au/getattachment/8de1a2d9-4484-4fd5-8d39-c61102d627bb/Final-Determination-2019-20-Notified-prices.aspx

[213] For more detailed information, refer to QLD government media release: http://statements.qld.gov.au/Statement/2019/6/21/regional-businesses-win-oneyear-extension-to-switch-power-tariffs

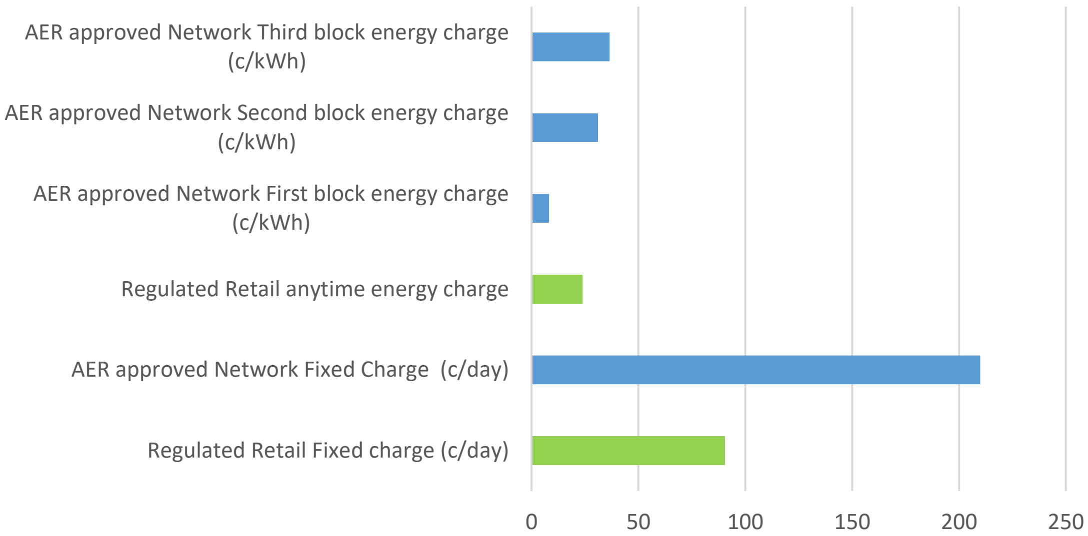
Figure A.21 Regulated Retail Price Framework in QLD



Source: AER analysis.

Under this framework, the underlying Ergon Energy inclining block tariff structure at the network level is not passed through to end-customers, as shown in the figure below.

Figure A.22 Network and Retail Price Comparison in Ergon Energy's network area – anytime energy tariff



Source: AER analysis.

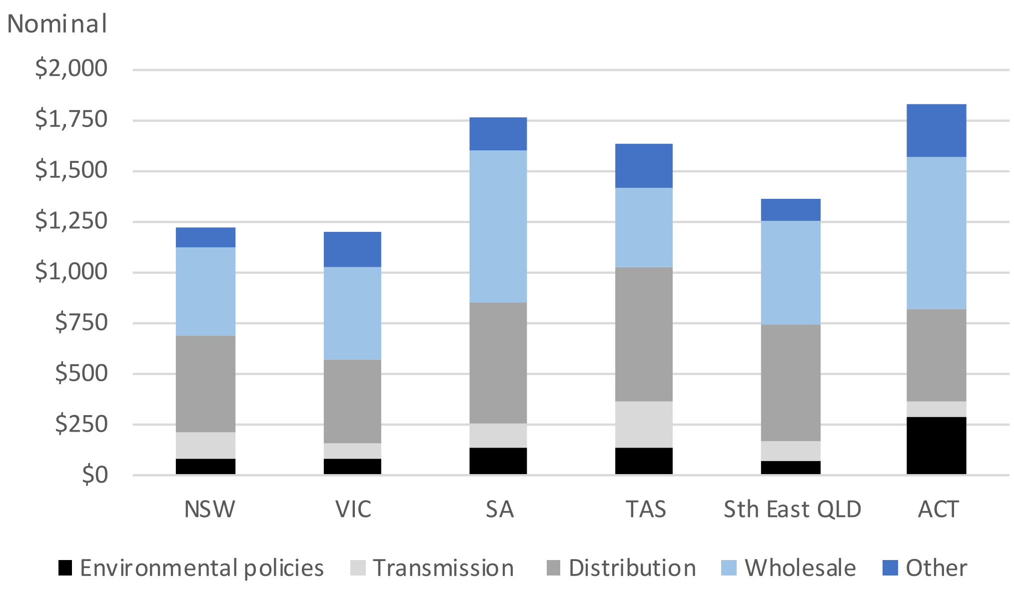
We have assumed for the purpose of assessing Ergon Energy's updated tariff structure statement that the Queensland Competition Authority will continue to adopt a flat tariff structure at the regulated retail level for residential and small business customers in the future. In this regard, residential and small business customers in Ergon Energy have a similar tariff experience to the customers in South East Queensland, namely they are only familiar with the flat tariff structure.

Comparison of supply chain costs by NEM region

As previously mentioned, the retail electricity market in the Energex distribution region is open to competition. As a result the market offers to customers in South East Queensland reflect the underlying costs in the supply chain, such as the costs of providing regulated electricity network services, retail margin, electricity purchase costs and the costs relating to environmental policy.

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

Figure A.23 Annual electricity supply chain costs by NEM region



Source: AEMC.

It is clear from the figure above that the wholesale energy purchases and the provision of electricity distribution and transmission services are the largest cost components in the underlying supply chain. Nevertheless, there is considerable variation in the relative share of each supply chain cost component across NEM regions. For example, the annual cost of environmental policy is the highest in the Australian Capital Territory, whereas wholesale energy purchase costs for the representative customer are highest in South Australia.

B Tariff design and assignment policy principles

Under the NER, the objective of tariff reform is to introduce cost reflective pricing. Tariff design and assignment policy plays an important role in achieving this objective by influencing:

- The extent that tariff structures signal to customers the true cost of supplying network capacity at different times.
- the speed with which customers take up cost reflective tariffs and which customers move to cost reflective tariffs.

In our assessment of a distributor's proposed tariff structure statements, we consider the distribution pricing principles and the network pricing objective under the NER.[214]

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

- consider customer impacts of the transition towards cost reflective pricing.[215]
- contemplate whether customers are going to be able to understand the charges they are likely to see.[216]

In other words, a distributor is allowed to depart from cost reflective pricing in circumstances where doing so will promote the achievement of these two additional principles.

This appendix provides the framework for our approach to assessing a distributor's proposed tariff design and policies for assigning and reassigning customers to tariffs. We have structured the appendix as follows:

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

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

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

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

- When should tariff assignment happen?

Distributors charge retailers for the provision of electricity network services to customers. Customers can be households, small businesses or large commercial and industrial customers connected to the high voltage network. The network tariff applying to each customer varies both in terms of structure and price level, depending on the type of metering installed, the voltage level of the connection and the extent of their usage of the network.

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

Tariff assignment is when, in accordance with its approved tariff structure statement, the distributor decides what tariff to apply to a new customer (i.e. a new connection).[217]

In contrast, tariff reassignment is when the distributor switches an existing customer from one network tariff to another network tariff. It should be noted that tariff reassignment can be initiated by the distributor or the customer (or retailer on behalf of their customer). A distributor initiated tariff reassignment occurs when the distributor identifies during their annual tariff review[218] that the customer is no longer eligible to remain on their current tariff. In this situation, the distributor will typically propose in their annual pricing proposal to reassign this customer to another tariff in the upcoming regulatory year. A customer initiated tariff reassignment occurs when a customer (or retailer acting on behalf of a customer) applies to the distributor to be reassigned to another tariff. The distributor will approve this application if the customer is able to demonstrate that they satisfy the eligibility criteria associated with the proposed tariff.

We consider that electricity distributors should:

- assign new customers to cost reflective tariffs upon initial connection, which would include a smart meter under current contestability rules.
- Re-assign existing customers who upgrade their connections through either adding embedded generation or upgrading to three-phase power to cost reflective tariffs upon completing the connection upgrade.
- Re-assign existing customers who receive a new smart meter as part of a retailer's meter replacement programme, 12-months after receiving that smart meter.

This approach balances the need to transition towards cost reflective tariffs with the need to ensure that customers are not unduly impacted by a change in tariff structure. It recognises that customer support for distributors' tariff strategies and their ability to understand these tariff strategies is an important element of fostering and maintaining

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

218 NER, cl. 6.18.4(b).

users' support for tariff reform generally.[219] If distributors adopt the same (re)assignment triggers there will be a more regular and consistent pace of tariff reform across distributors and jurisdictions.

New customers should face cost reflective tariffs

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

- such tariffs incentivise efficient use of the network[220] and investment in energy efficiency in the construction of a new building/premise.[221]
- newly connected customers are less likely to be surprised by their network charges even where they are moving premises. This is because as they either have no prior tariffs to compare with or prior tariffs were at another connection with different appliances and heating, cooling or lighting needs.

Assessment criteria:

We consider that a distributor should assign new customers to a cost reflective tariff upon connection to the electricity distribution network. Note that we consider that a time of use energy tariff can be designed to be as cost reflective as a demand tariff.

Our preference for the default network tariff to have a cost reflective structure is reflected in our recent TSS decisions in NSW, Australian Capital Territory, Tasmania and the Northern Territory, where we required distributors to adopt a default tariff with either a time of use or demand structure, as highlighted in the table below.

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219 NER, cl. 6.18.5.

220 See D.4.1.

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

Table B.1 Current default network tariffs by distributor

Jurisdiction	Distributor	Default Network Tariff
New South Wales	Ausgrid	Demand tariff
New South Wales	Endeavour Energy	Demand tariff
New South Wales	Essential Energy	Time of use tariff
Australian Capital Territory	Evoenergy	Demand tariff
Tasmania	TasNetworks	Time of use tariff
Northern Territory	Power and Water	Demand tariff

Source: AER analysis.

Upgrading customers should face cost reflective tariffs

Existing customers may decide to upgrade their electricity connection by:

- installing embedded generation, such as rooftop solar
- increasing the capacity of their connection, such as installing three-phase power.[222]

Distributors can reasonably expect customers that upgrade their connections to understand that the upgrade will impact their network charges. These customers, along with the businesses installing rooftop solar and three-phase power, are in a position to understand the impact of a cost reflective tariff on their network charges.

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

Assessment criteria:

We consider that a distributor should reassign existing customers that upgrade to a smart meter to a cost reflective tariff. Note that we consider that a time of use energy tariff can be designed to be as cost reflective as a demand tariff.

Our preference for upgrading customers to be on cost reflective tariffs is reflected in our recent TSS decisions in NSW, Australian Capital Territory, Tasmania and the

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

Northern Territory, where we required distributors to adopt policies that result in existing customers that upgrade their metering being re-assigned to a cost reflective network tariff.

Table B.2 Tariff reassignment policy for meter upgrade customers by selected distributor

Jurisdiction	Distributor	Policy description
New South Wales	Ausgrid	Existing Customer that upgrades meter is reassigned to introductory demand tariff for 12 months
New South Wales	Endeavour Energy	Existing Customer that upgrades meter is reassigned to transitional demand tariff.[223]
New South Wales	Essential Energy	Existing Customer that upgrades meter is reassigned immediately to time of use tariff.[224]
Australian Capital Territory	Evoenergy	Existing Customer that upgrades meter is reassigned to default demand tariff after 12 months
Tasmania	TasNetworks	Existing Customer that upgrades meter is reassigned to time of use tariff after 12 months
Northern Territory	Power and Water	Existing Customer that upgrades meter is reassigned immediately to demand tariff.[225]

Source: AER analysis.

Replacement meter customers should face cost reflective tariffs as long as adequate safeguard measures are in place

Under the AEMC's tariff reforms, metering providers must replace basic accumulation meters[226] that are faulty with smart meters[227]—this is automatic without any action by customers on their behalf.

223 The AER has not waived the requirement for a 12 month grace period because Endeavour Energy's transitional and cost reflective demand tariffs are set at a discount to flat tariff.

224 The AER has not waived the requirement for a 12 month grace period because Essential Energy's cost reflective tariffs are set at a discount to flat tariff.

225 The AER has not waived the requirement for a 12 month grace period because end-customers are not impacted because the cost reflective network tariff structure is not passed through to end-customers at the regulated retail pricing level.

226 A basic accumulation meters are defined as a meter that is only capable to recording the customers' energy consumption during the billing period, typically 90 days.

227 Smart meters are defined as a meter that is capable of recording the customer's energy consumption at different time intervals during the day and to remotely transmit these data to a third party for billing purposes. Smart meters also have other functionality such as remote connection and disconnection.

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

Existing customers that receive a new smart meter on account of their basic accumulation meter being faulty are not actively engaging with their electricity supply. Circumstances beyond their control are impacting their metering circumstances. We do not consider the immediate reassignment of these customers to a fully cost reflective tariff to be appropriate in these circumstances given that these customers may not have had adequate time to understand the cost reflective tariff and to explore opportunities to mitigate the impact of a change in tariff structure.[228] Therefore, we consider that the distributor should implement appropriate safeguard measures when reassigning these customers to a cost reflective tariff, such as reassigning these customers after expiration of a 12-month sampling period. This delay will assist these customers to better understand their load characteristics by gathering sufficient information to make an informed decision when selecting a retail pricing offer.

The 12-month period is to help customers to understand a full year of their consumption and demand profile (i.e. so they understand their demand characteristics in all seasons). This will help them adjust to the reassignment to a new cost reflective tariff following the grace period.

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

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

Even so, we consider that these customers will also benefit from a 12-month data-sampling period. We would like to hear from the Queensland distributors and other stakeholders, on whether distributors should provide all customers with a 12-month data-sampling period to help them better engage with their electricity charges and usage patterns.

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

Assessment criteria:

We consider that a distributor should reassign existing customers to a cost reflective tariff that have their basic accumulation meter replaced with a smart meter. To satisfy the customer impact principle in the NER, distributors should adopt safeguard measures in respect to these tariff reassignments, such as a 12-month grace period or similar transitional mitigation measures.

It is also important to note that in our recent TSS decisions in NSW, Australian Capital Territory, Tasmania and the Northern Territory, we allowed some of these distributors to immediately reassign existing customers with replacement smart meters to a more cost reflective tariff. We also allowed Ausgrid to assign these customers to a transitional demand tariff for a period of 12 months. This serves the same purpose as a 12 month grace period given that under Ausgrid's approach these customers are reassigned to the demand tariff at the end of this period. A summary of the tariff reassignment policies for meter replacement customers in NSW, ACT, NT and Tasmania is provided in the table below.

Table B.3 Reassignment policy for existing replacement meter customers by selected distributor

Jurisdiction	Distributor	Policy description
New South Wales	Ausgrid	Customer is reassigned to transitional demand tariff for 12 months
New South Wales	Endeavour Energy	Customer is reassigned immediately to transitional demand tariff.[229]
New South Wales	Essential Energy	Customer is reassigned to immediately to time of use tariff.[230]
Australian Capital Territory	Evoenergy	Customer is reassigned to default demand tariff after 12 months
Tasmania	TasNetworks	Customer is reassigned to time of use tariff after 12 months
Northern Territory	Power and Water	Customer is reassigned immediately to demand tariff.[231]

Source: AER analysis.

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229 The AER has not waived the requirement for a 12 month grace period because Endeavour Energy's transitional and cost reflective demand tariffs are set at a discount to flat tariff.

230 The AER has not waived the requirement for a 12 month grace period because Essential Energy's cost reflective tariffs are set at a discount to flat tariff.

231 The AER has not waived the requirement for a 12 month grace period because end-customers are not impacted because the cost reflective network tariff structure is not passed through to end-customers at the regulated retail pricing level.

Retail price regulation will influence tariff reassignment

In some jurisdictions, such as Queensland, Tasmania and the Northern Territory, there is retail price regulation. Retail price regulation is a relevant consideration in our decision on acceptable reassignment practices.

In the Northern Territory, the Government caps and subsidises flat retail electricity tariffs. The retailer faces cost reflective tariffs from the distributor but converts these to a flat tariff for customers under the regulatory arrangements in the Territory. This situation supports the more aggressive approach to tariff reassignment by Power and Water Corporation, but only where there is minimal, if any, impact on customers from doing so.

This principle also underpinned our final TSS decision for TasNetworks, where we required that TasNetworks default network tariff for residential and small business customers have a cost reflective structure.[232] This decision resulted in a more aggressive approach to the introduction of cost reflective than TasNetworks' proposal of a voluntary opt-in approach.[233]

We note that customers in Ergon Energy's network area are currently subject to regulated retail pricing. A key element of this framework is the Queensland Government's uniform tariff policy that results in customers in regional Queensland paying similar amounts for their retail electricity services as customers in Energex's network area. The key consideration in our assessment of Ergon Energy's tariff structure statement proposal is the extent that it is reasonable to consider that the proposed changes to structure of network tariffs will be reflected in regulated retail tariffs set by the Queensland Competition Authority. On the basis of past QCA electricity retail price determinations, the AER notes that the regulated retail tariff has generally reflected the underlying network tariff structures, except where customers are assigned to a transitional retail tariff.[234]

Assessment criteria:

We consider that impact mitigation measures such as the 12 month grace period and equivalent transitional arrangements are less important in situations where it is reasonable to believe that customers will not be impacted by proposed tariff reform reforms under the regulated retail pricing framework.

232 AER, *Final Decision - Attachment 18 - Tariff Structure Statement - TasNetworks*, April 2019.

233 TasNetworks, *Revised Tariff Structure Statement*, January 2019.

234 It should be noted that the QCA has adopted Energex's flat structure for the regulated retail tariff for residential customers, rather than Ergon Energy's inclining block tariff structure at the network level. For more information on this issue refer to: http://www.qca.org.au/getattachment/8de1a2d9-4484-4fd5-8d39-c61102d627bb/Final-Determination-2019-20-Notified-prices.aspx

Anytime tariffs are not cost reflective

Anytime tariffs are tariffs where the usage charge is not dependent on the time of usage or demand. Common examples include flat tariffs, inclining block tariffs and declining block tariffs.

Anytime tariffs are easy for customers to understand.[235] However, they do not reflect the cost drivers of distributors.[236] That is, they charge customers the same amount per unit of electricity transported during peak and off-peak periods. As a result customers on anytime tariffs receive a network price signal that is:

- too low during the peak period when the electricity network is more likely to be constrained.
- too high during the off-peak period when there is ample network capacity.

We are not satisfied that this is in the long term interest of customers because it encourages customers to use the network during high cost peak times, which has the potential to result in unnecessary investments in additional network capacity, leading to customers paying higher than otherwise network prices in the long term.

The need to satisfy customer demands for network capacity at peak times is a significant underlying driver of the costs of providing electricity distribution services. Therefore, the main determinant of how much cost customers are imposing on the network is how much they demand when the localised network is approaching its capacity constraints. Demand tariffs and time of use tariffs can both be designed to signal to customers the marginal cost of supplying network services during periods when the network is constrained.

We consider that distributors should no longer offer customers who are on a cost reflective tariff the ability to opt-out to anytime energy network tariffs.[237] The risks of allowing continued access to anytime tariffs – inefficient use of, or investment in, the network – outweigh the benefits of customers understanding these simple tariff structures.[238] After all, this represents continuation of the status quo, acknowledged by policy makers as inappropriate. We note retailers can continue to offer anytime energy retail tariffs when facing cost reflective network tariffs but that is a choice for them in their ongoing management of market contracts and spot prices.

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235 NER, cll. 6.18.5(h) and 6.18.5(i).

236 NER, cll. 6.18.5(f) and 6.18.5(g).

237 Except in the situation where the distributor is required to set the cost reflective tariff at a discount to the flat tariff, refer to AER, *Final TSS decision for Essential Energy*: https://www.aer.gov.au/system/files/AERper cent20-per cent20Finalper cent20decisionper cent20-per cent20Essentialper cent20Energyper cent20distributionper cent20determinationper cent202019-24per cent20-per cent20Attachmentper cent2018per cent20-per cent20Tariffper cent20structureper cent20statementper cent20-per cent20Aprilper cent202019.pdf

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

Assessment criteria:

We consider that a distributor should not allow customers with smart meters to opt-in to a flat tariff, except in the limited circumstances where customers have non-financial reasons for doing so.

In our recent TSS decisions in NSW, Australian Capital Territory, Tasmania and the Northern Territory, we approved Endeavour Energy and Essential Energy proposals to allow customers to opt-in to flat tariffs but only on the condition that the cost reflective tariffs were set at a discount to the legacy flat tariffs. Given the lack of financial incentive to opt-out of the cost reflective tariffs, we do not anticipate that many customers will take up this option in the future. It does, however, provide an impact mitigation measure for customers with unusually peaky load profiles, but it should be noted that it is our preference for the flat tariff to become increasing more expensive than the cost reflective tariff over time. This will ensure that peak load customers will ultimately have the incentive to manage their peak demand, rather than to avoid these costs by remaining on the flat tariff.

The ACCC supported prescribed tariffs

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

- a compulsory data sampling period for customers following smart meter installation, which is the approach we have recommended
- a requirement for retailers to offer flat energy retail tariffs to customers that distributors charge more cost reflective network tariffs to
- additional targeted assistance for vulnerable customers.[239]

The ACCC suggested these measures be considered as a package of recommended changes to the existing NEL and NER requirements.

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

In spite of this focus, we consider that coupled with complementary measures, prescribed tariff assignment can be an effective means to progress tariff reform. In the

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

Northern Territory, Power and Water Corporation proposed a prescribed assignment policy for residential customers.[240] However, as noted earlier, the Northern Territory Government regulates and subsidises retail electricity prices.[241] This means in this case the move to prescribed network tariff assignment is highly unlikely to come at the cost of customer support for reform, to reduce customer choice or increase retail prices.

Customers should have choice in cost reflective tariffs

We consider that default assignment to cost reflective tariffs (with optional alternative cost reflective tariffs available) will lead to a faster adoption of cost reflective tariffs compared to other assignment policies. Indeed, we encourage distributors to introduce more cost reflective optional tariffs – such as critical peak pricing or rebates – that could build customer acceptance of more complicated tariffs over time and encourage retail offerings that support a wider rollout of these more cost reflective tariff structures.

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

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

Our commitment to ensuring that customers have a choice of cost reflective tariffs is reflected in our recent TSS decision for Ausgrid, where we required that customers on demand tariffs be given the opportunity to be voluntarily re-assigned to the seasonal time of use energy tariff.[242]

The inclusion of opt-in cost reflective tariffs in the distributor's tariff portfolio strikes an appropriate balance between the need for cost reflective tariffs against the necessity of engendering customer support for tariff reform through managing impacts and customers' ability to understand tariffs. While customer choice is important, we consider network tariffs must designed with regard to the network characteristics in which they apply which we discuss in the below sections.

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

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

[242] AER, *Final Decision - Attachment 18 - Tariff Structure Statement*, April 2019.

Assessment criteria:

We consider that a distributor should provide a choice of cost reflective tariffs so that customers can better match their network usage requirements with their tariff preferences, noting that we consider that a time of use energy tariff can be designed to be as cost reflective as a demand tariff.

Our preference for distributors to offer a choice of cost reflective tariffs is reflected in our recent TSS decisions in NSW, Australian Capital Territory, Tasmania and the Northern Territory, where we required distributors to include opt-in cost reflective tariffs in their network tariff portfolio, as highlighted in the table below.

Table B.4 Tariff choice options for residential customers by distributor

Jurisdiction	Distributor	Opt-in cost reflective tariffs
New South Wales	Ausgrid	Seasonal time of use tariff Demand tariff
New South Wales	Endeavour Energy	Flat tariff Demand tariff
New South Wales	Essential Energy	Flat tariff Demand tariff
Australian Capital Territory	Evoenergy	Time of use tariff
Tasmania	TasNetworks	Demand tariff
Northern Territory	Power and Water	Time of use tariff.[243]

Source: AER analysis.

What tariffs should distributors offer?

In this section, we consider what tariffs distributors should offer to customers, noting our preference for distributors to offer customers a portfolio of cost reflective tariffs. We will focus on tariffs for residential and small business customers, unless otherwise indicated.

In summary, we recommend that distributors offer these customers:

243 The AER has not waived the requirement for a 12 month grace period because end-customers are not impacted because the cost reflective network tariff structure is not passed through to end-customers at the regulated retail pricing level.

- time of use energy tariffs – these tariffs are as cost reflective as any other more average tariff with a pre-defined peak period and are well understood by customers
- demand tariffs – these tariffs are as cost reflective as any other more averaged tariff with a pre-defined peak period and reinforces with customers that demand is an important cost driver.

We consider that distributors:

- with a dominant peak demand season should aim to offer seasonal monthly demand tariffs accompanied with flat energy charges.
- without a dominant season should aim to offer monthly demand tariffs with time of use energy charges.
- highly cost reflective tariffs for large business customers – large business customers are well informed and are large users of electricity, therefore distributors can assume that they understand highly cost reflective tariffs.
- flat tariffs for customers with accumulation meters – the technological limitations of accumulation meters require anytime flat tariffs, whose benefits are simplicity and are slightly more cost reflective than inclining block tariffs.[244]

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

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

In this section, we:

- discuss what makes a tariff cost reflective
- assess time of use energy tariffs
- assess demand tariffs
- consider the role for transitional tariffs
- identify opportunities for a greater role for more highly cost reflective tariffs

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[244] Except where it can be demonstrated that the IBT structure provides a smoother transition for relatively large users that are moving above or below the extent of usage threshold for compulsory demand pricing, see p. 56 of AER, *Draft TSS decision*: https://www.aer.gov.au/system/files/AERper cent20-per cent20Draftper cent20decisionper cent20-per cent20NSWper cent20distributionper cent20networkper cent20serviceper cent20providersper cent20-per cent20Tariffper cent20structureper cent20statementper cent20-per cent202017-19.pdf

- identify opportunities for introducing innovative network tariffs
- consider what tariffs distributors should offer customers with accumulation meters
- identify appropriate tariff structures for large business customers.

Efficient tariffs align with cost drivers

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

We have heard from stakeholders that 'demand issues require a demand charge and energy issues require an energy charge'. This position has an appealing simplicity, however we consider that efficient tariff design is more complicated in practice.

Distributors can indeed face two types of issues:

- peak demand issues are situations where excess demand for capacity is driving the need to invest in additional network capacity. Distributors typically experience demand issues when people get home from work on the hottest days and turn on their air conditioners or on coldest days turn on their electric heating, while transport systems and businesses are still operating at or near full capacity
- energy issues are situations where electricity usage is driving network costs. This includes any costs created by insufficient electricity usage.

Customer demand and energy usage are closely related. A customer that sustains a demand of 1kW of electricity for one hour will use 1kWh of electricity. At a residential and small business level, distributors see demand constraints based on coincident demand. That is the total demand from customers within the feeder zone.

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

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

Based on our analysis of data provided by NSW distributors, we consider that time of use tariffs can be designed to be as cost reflective as demand tariffs.[245]

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[245] AER, *Draft Decision, NSW Distributors, Attachment 18, Tariff Structure Statement - Appendix B,* November 2018.

It should be noted that distributors also need to design network tariffs that are appropriate for their circumstances, including:

- The level of customer knowledge and acceptance of cost reflective network pricing within the customer base;
- The responsiveness of customers to changes in the price level, such as in the situation where a new tariff structure has been introduced; and
- The extent that the electricity network is expected to face congestion issues in the foreseeable future.

Distributors in the early stages of the tariff reform process need to be cognisant when designing their cost reflective tariffs that many of their customers have made significant investments in energy appliances in response to the incentives under flat tariffs. We also consider that these customers may not be able to easily understand more complicated tariff structures and may as a consequence struggle to appropriately respond to these new tariff incentives in the short term.

The declining cost of energy technologies, such as solar PV and batteries, could mean that customers are more responsive to changes in the level and structure of electricity tariffs than in the past. As a consequence, distributors must take account of these factors when designing their network tariffs, particularly in regard to the efficient recovery of the sunk residual costs associated with their existing network.

The presence of significant excess capacity is also an important consideration for distributors to take into account when designing efficient tariff, particularly in environments of weak peak demand growth. The combination of excess capacity and weak peak demand growth results in the reduced need for distributors to augment the electricity network. It also means that the medium-term rationale for tariff reform is no longer about conveying peak price signals to encourage customers to reduce their peak demand where it is economically desirable to do so. We consider the challenge for distributors in this environment is to design tariffs to:

- Encourage customers to increase their utilisation of the network where there it is economically desirable to do so, noting that it may be in the long-term interests of customers to transition to high LRMC peak charges in locations where it is reasonable to believe that congestion issues may arise due to future peak demand growth.
- Recover the residual costs associated with the provision of existing network capacity in a manner that minimises the distortion to efficient consumption and investment decisions of electricity users. This is particularly important in situations where customers are willing and able to respond to price signals by investing in technology solutions to reduce their reliance on the electricity grid, or to disconnect from the grid altogether.

Time of use tariffs are easy to understand

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

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

Distributors often remove peak charges from days unlikely to see system or zonal peaks, such as:

- weekends – where business demand is reduced;
- public holidays – where business demand is reduced;
- low demand seasons – where due to reduced air conditioning or heating use by customers reduces the probability of a demand approaching capacity constraints.

Customers are familiar with being charged on the basis of how much electricity they consume. Distributors charge customers with accumulation meters based on their energy consumption, and time of use energy tariffs are well established in some jurisdictions. In general, we consider that customers will be able to understand time of use energy tariffs.

We also note that time of use energy tariffs can be relatively efficient given that peak energy consumption tends to be correlated with user demand during coincidental peaks.[246] In general terms we consider that more cost reflective time of use energy tariffs will have more targeted peak periods, such as in the case of Ausgrid peak energy charges applying only to peak times in summer and winter, and not including peak charges during the milder spring and autumn periods. A more targeted peak period will require distributors to have a relatively high ratio of peak to off-peak charges given that the peak price is more closely aligned to long run marginal cost, leading to more efficient network investment expenditure over the long term.

The current residential time of use energy tariff structures for a sample of distributors are summarised in the table below.

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[246] This is based on our analysis of NSW distributors' interval meter data. We found that Ausgrid's proposed seasonal time of use energy tariffs were the most cost reflective of all tariffs proposed by NSW distributors for residential customers.

Table B.5 Peak energy consumption charges by selected distributors

Distributor	Type of Tariff	Description	Ratio of peak to off-peak (2023-24)
TasNetworks	Default Tariff	7am to 10am and 4pm to 9pm peak on weekdays year-round with all other times off-peak.	4.9
Evoenergy	Opt-in Tariff	7am to 9am and 5pm to 8pm peak everyday year-round, 9am to 10pm shoulder period (excluding peak period) with 10pm to 7am off-peak.	3.2
Ausgrid	Opt-in Tariff	2pm to 8pm weekday peak from November to March, 5pm to 9pm weekday peak from June to August, of 7am to 10pm weekday shoulder period (excluding peak period) year-round, with all other times off-peak.	9.5
Essential Energy	Default Tariff	5pm to 8pm weekday peak year-round, shoulder period of 7am to 10pm weekdays (excluding peak period) year-round, with all other times off-peak.	3.3

Source: AER analysis.

The table above shows that there are considerable differences between distributors in terms of the design of their time of use energy tariffs. We consider that these differences are acceptable where they reflect the unique circumstances of the distributor.

We accept that the introduction of more targeted peak price signals may not be appropriate for every distributor. It may be more appropriate for distributors that are more advanced in the tariff reform process, such as Ausgrid, to introduce more complex cost reflective tariffs given that they have established a reasonable level of customer acceptance and understanding of time of use pricing structures.[247]

However, for distributors in the early stages of the tariff reform process, such as Essential Energy and TasNetworks, it is often more appropriate to have relatively simple time of use tariffs that are easier for customers to understand[248] and to apply a lower peak to off-peak price ratio to foster customer acceptance by minimising the impacts association with the introducing more cost reflective pricing.

We accept it is often difficult for distributors with diverse peak demand characteristics across their network, such as Essential Energy, to introduce more targeted cost reflective tariffs due to the complexity and administration costs of doing so.

We consider time of use energy tariffs can be designed to be sufficiently cost reflective to be approved as default tariffs or opt-in tariffs for residential and small business customers.

247 Ausgrid currently has almost 450,000 residential and small business customers on cost reflective network tariffs.

248 Essential Energy's time of use tariff is based on a single peak period year-round, which makes it easy for customers to remember when peak charges apply and change their behaviour accordingly.

Assessment criteria:

We consider that time of use energy tariffs can be designed to be as cost reflective as demand tariffs. We consider that time of use energy tariffs may be more appropriate for distributors at the early stage of the tariff reform process given that they are easier than demand tariffs for customers to understand.

Demand tariffs can be cost reflective

Demand tariffs charge customers based on the maximum point in time demand (typically over a 30-minute period), as measured in kW or kVa, typically on a daily or monthly basis.

The demand charge can be:

- anytime demand – where the charge is the maximum 30-minute demand at any time of the day or month.
- peak demand – where the charge is the maximum 30-minute demand during a pre-defined peak period during the day or month.[249]
- time of use demand – where the charge is the maximum 30-minute demand during each of the pre-defined peak, off-peak and shoulder periods, during the day or month.[250]
- Seasonal time of use demand - similar to a time of use demand, except that the pre-defined peak periods covers summer and winter months of the year.[251]

The current residential demand tariff structures for a sample of distributors are summarised in the table below.

Table B.6 Maximum demand charges by selected distributors

Distributor	Tariff Type	Demand charge	Other charges
Ausgrid	Introductory demand tariff ToU demand tariff Demand tariff[252]	Seasonal maximum monthly demand charge with a higher demand charge from November to March. Charging windows also vary according to whether it is a weekday or working weekday	Fixed charge and a time of use energy charge

[249] Evoenergy currently applies a peak demand charge for customers with smart meters.

[250] Essential Energy currently has a time of use demand charge for large business customers.

[251] Endeavour Energy currently has a seasonal time of use demand charge for large business customers.

[252] This tariff includes an anytime energy consumption charge, whereas the other two demand tariff include a time of use energy consumption charge. See: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/ausgrid-annual-pricing-2019-20

Distributor	Tariff Type	Demand charge	Other charges
Endeavour Energy	Default transitional demand tariff Opt-in cost reflective demand tariff	Seasonal maximum monthly demand between 4pm and 8pm on weekdays, with a higher demand charge from November to March.	Fixed charge and a flat energy charge.
Essential Energy	Opt-in demand tariff	Maximum monthly demand between 5 and 8pm on weekdays, with shoulder charges between 7am and 5pm and 8am–10pm. Note, this is on an opt–in basis, the default tariff is time of use energy with fixed charge.	Fixed charge and a time of use energy charge.
Evoenergy	Default demand tariff	Maximum daily demand between 5pm and 8pm every day.	Fixed charge and flat energy charge.
Power and Water	Default demand tariff	Seasonal maximum monthly demand between midday and 9pm from October to March.	Fixed charge and a flat energy charge.
TasNetworks	Opt-in demand tariff	Maximum daily peak and off-peak demand, with the peak between 7am to 10am and 4pm to 9pm weekdays. Note, this is on an opt–in basis, the default tariff is time of use energy with fixed charge	Fixed charge.

Source: AER analysis.

In our 2017 final decisions on tariff structure statements, we expressed concern with residential demand charges based on a customer's demand over a month or longer. We noted that it is not an individual customer's monthly peak demand that drives network costs, but to the extent which that customer's demand contributes to network congestion near capacity constraints.[253] As above, the ACCC also made this observation. [254]

For our recent TSS decisions for NSW distributors, we tested the correlation between the peak demand quantities of a sample of interval metered customers under a range of more cost reflective tariff structures with the peak demand of these customers in top 40 hours of the year.[255] This analysis found that demand tariffs can be designed to be as cost reflective as time of use energy tariffs, particularly where the demand tariff structure includes time of use energy charges and applies the demand charge on a seasonal basis.

253 AER, *NSW electricity distribution determinations Ausgrid, Endeavour Energy, Essential Energy 2019 to 2024, Issues Paper*, June 2018, p. 140.

254 Australian Competition and Consumer Commission, *Restoring electricity affordability and Australia's competitive advantage, Retail Electricity Pricing Inquiry Final Report,* June 2018, p. 182.

255 AER, *Draft Decision - Attachment 18* - Tariff Structure Statement - *Appendix B*, November 2018.

We consider demand tariffs can be designed to be sufficiently cost reflective to be approved as default tariffs or opt-in tariffs for residential and small business customers. We also recognise that the more cost reflective versions of both demand tariffs and time of use tariffs are often complex and difficult for customers to understand, particularly if they include a seasonal peak charging parameter. It is for this reason we have been careful in our past TSS decisions to approve the introduction of more complex seasonal tariffs. Typically we require that these tariffs be offered by distributors as opt-in tariffs, except where the customer impact concerns have been mitigated by the unique circumstances of the distributor[256] or the distributor has also introduced appropriate mitigation measures such as a 12 month grace period or transitional variants of the seasonal demand tariff. [257]

Assessment criteria:

We consider demand tariffs are capable of being designed to be cost reflective.

Capacity tariffs are a complex form cost reflective pricing

We note that some distributors, such as Ausgrid and Evoenergy currently have capacity tariffs for large business customers.

We consider these tariffs to be complex demand tariffs, rather than capacity tariffs given that they are based on the individual customer's maximum peak demand rather than the installed capacity as measured at the metering or coupling point.

Under these tariffs, the capacity charge is applied to the individual customer's highest half hourly maximum kW demand recorded in the peak charging window during the preceding 12 months. The historical basis of this charging parameter results in the capacity charging parameter having similar efficiencies properties to a fixed charge the customer pays a fixed amount for a period of up to 12 months, irrespective of their actual usage.[258] [259] This design feature results in the capacity charging parameter

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[256] Such as in the case of Power and Water where retail price regulation ensures that end-customers are not unduly impacts by the introduction of more complex network tariff structures.

[257] Such as in the case of Endeavour Energy and Ausgrid/s final TSS decisions

[258] The individual customer is permitted to apply to the distributor to have their capacity charge reset to a lower kW quantity. The distributor will only approve this reset where customer can provide evidence that they have permanently reduced their maximum demand, such as by installing power factor correction equipment or upgrading their plant and equipment.

[259] It should be noted that if the individual customer exceeds their historical highest kW maximum demand during the peak period in the current billing period, the capacity charge will immediately increase to reflect this new peak kW value.

being more efficient than a demand charging parameter from a residual cost recovery perspective.[260]

These tariffs are highly cost reflective given that their structure comprises both a kW-based charging parameter and time of use energy charging parameters. The economic merit of this approach is supported by our recent econometric analysis of alternative cost reflective tariff structure.[261]

It is also relevant to note that the current Ausgrid and Evoenergy capacity tariffs apply to large business customers. We consider this type of customer to be capable of understanding and responding to complex tariff structures.

It is interesting to note that the Queensland distributors proposed in their tariff structure statements submitted to the AER on 14 June 2019 to introduce capacity tariffs for residential and small business customers on an opt-in basis from 1 July 2020. The proposed design of these capacity tariffs differ to the current Ausgrid and Evoenergy capacity tariffs for large business customers in the sense that the customer (or their retailer) is required to select a kW capacity threshold to apply as the quantity basis for billing of the capacity charging parameter. This design feature raises some interesting issues from an economic efficiency perspective, as explored in the illustrative example below.

Illustrative example: Efficiency properties of the Queensland distributor's capacity charging parameter

To illustrate the potential impact on economic efficiency of the unusual properties of the proposed capacity charging parameter consider a low income single person household with only essential energy requirements - cooking, refrigerating and lighting. They have an air conditioner that is only used to provide a bit of relief on extreme hot days. If we assume for the purpose of this example that the customer's highest kW peak demand is 5.5 kW, which occurs on a limited number of extremely hot summer days each year. There are three broad strategies that the customer, or their retailer, could pursue to select their capacity threshold, as summarised below:

- The customer could choose to have a zero capacity threshold and pay their excess capacity charge each month on the basis of their actual maximum demand during the peak period. We note that this will result in the capacity charge having similar properties to a demand charge.[262]

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[260] Ausgrid, *Attachment 10.01* - Tariff Structure Statement - 2019-24 *Regulatory Control Period - Ausgrid Distribution Determination*, April 2018, p. 10.

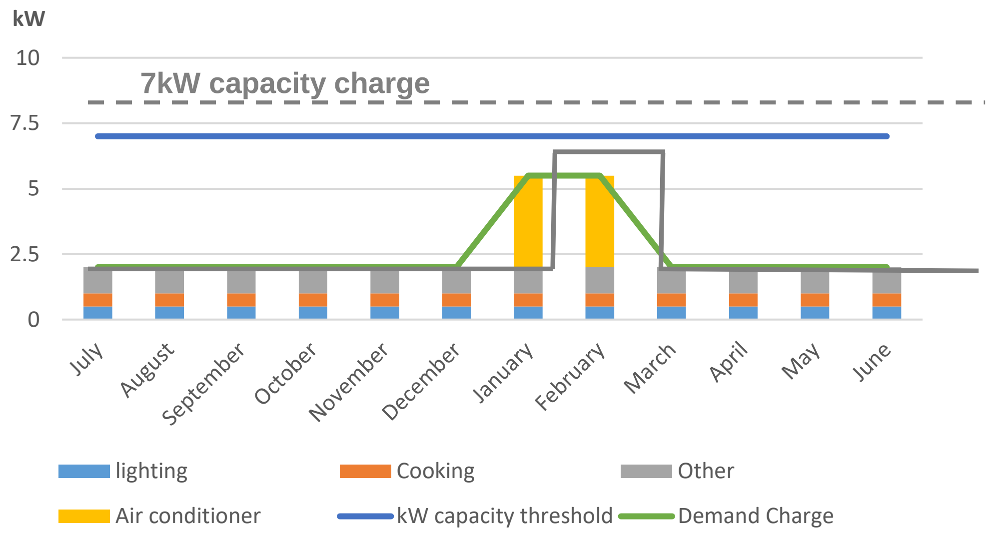
[261] AER, Attachment 18 - *Tariff Structure Statement - Draft Decision* - Ausgrid Distribution Determination, November 2018, p. 18-22.

[262] Under this scenario, the capacity charge operates in a similar manner to a demand charge from a billing perspective. Unlike the demand tariff, the customer will still incur additional transactions costs to be in a position to make this decision.

- The customer could choose to have a 2.5 kW capacity threshold to cover their essential capacity requirement, but pay an excess capacity charge when they use their air conditioner in summer. This will result in the capacity charge having both fixed and variable properties.
- The customer could choose a higher capacity threshold of 7kW that is sufficient to ensure that they will not be liable for excess capacity charges in the future. This will result in the capacity charge having similar properties to a fixed charge.[263]

If we assume that the customer in this illustrative example is risk averse, then they will select the 7 kW capacity threshold to avoid bill shock from excess capacity charges being imposed when they use their air conditioner on extreme hot days. Under this assumption, the customer will pay a fixed amount per month for their 7 kW capacity requirement during the financial year, denoted by top horizontal line in the figure below. Under these assumptions, the capacity charge has the same efficiency properties as a fixed charge in the sense that the capacity charge becomes a fixed amount per month. This contrasts with a demand charge, where the amount the customer pays varies each month in accordance with the customer's level of peak demand recorded in each month,[264] as illustrated by the lower bold line in the figure below.

Figure B18.3 Illustrative example - capacity charge vs demand charge



Source: AER analysis.

[263] This assumes that the customer does not change their appliance mix during the financial year.

[264] It should be noted that if the customer chooses a "zero" capacity threshold, the capacity tariff will have similar efficiency properties to a demand tariff as the amount payable will be based on the excess capacity charge, which is applied to the customer actual peak maximum demand. The customer will presumably still incur additional transactions costs (compared to the demand tariff) in order to be in a position to make this assessment.

If it is assumed in this illustrative example that the customer chooses a relatively high capacity threshold, the customer has little, if any, immediate financial incentive to reduce their maximum demand below their selected capacity threshold, even during hot summer evenings when peak demand is at its highest. In fact, it is reasonable to assume that they will use their air conditioning more frequently given that there is no risk of excess capacity charges being imposed - they have paid in advance for 7 kW of capacity requirement. We are concerned that customers could respond to this incentive by increasing their peak demand when they derive the highest value from their network services, such as on extreme hot and cold days when the network is more likely to be constrained.[265] As a consequence we are not satisfied that the capacity charging parameter proposal of the Queensland distributors contributes to compliance with the distribution pricing principles in the Rules.

We note that that the current capacity tariffs offered by Ausgrid and Evoenergy have addressed this efficiency issue by not requiring the customer or retailer to actively be involved in the selection of their kW capacity value. It should also be noted that the efficiency properties of these tariffs is improved by the inclusion of a peak energy charging parameter in the capacity tariff structure for the purpose of signalling long run marginal cost. It is also consistent with our past decisions to approve this form of cost reflective pricing in other jurisdictions, see table below.

Table B.7 Evoenergy and Ausgrid examples of capacity tariffs

Charging parameter	Unit	Description of charging parameter
Fixed charge	c/day	This is a daily charge that is applied on a $ per day basis to each energised connection point, regardless of the level of usage.
Peak energy charge	c/kWh	This charge is applied on a cents per KWh basis for the total energy consumption recorded under this tariff during the billing period.
Shoulder energy charge	c/kWh	This charge is applied on a cents per KWh basis for the total energy consumption recorded under this tariff during the billing period.
Off-peak energy charge	c/kWh	This charge is applied on a cents per KWh basis for the total energy consumption recorded under this tariff during the billing period.
Capacity charge	c/kW/m	This is a monthly charge that is applied on a $ per kilowatt (kW) for the maximum kW demand recorded during the peak charging window in the previous 13 months.

Source: AER analysis.

[265] The customer will also have less financial incentive compared to a demand tariff to pursue demand management initiatives.

Transitional tariffs can play an important role in the early stage of the tariff reform process

We consider that transitional tariffs play an important role in the early stages of the tariff reform process if the distributor is concerned over the customer impact of moving from flat tariffs to more cost reflective tariffs.

While we require that distributors adopt a cost reflective structure for their default tariffs, we accept that in some circumstances it is appropriate for a distributor to transition the peak charging parameter to long run marginal cost over a reasonable timeframe, where it is necessary to do so to comply with the customer impact principle under the Rules.[266]

For our recent TSS decisions for Endeavour Energy, we approved their proposal to adopt a transitional demand tariff for residential customers on the grounds that it is appropriate for a distributor at the early stage of the tariff reform process to adopt a cautious approach to the introduction of more cost reflective pricing. To minimise the efficiency loss associated with a transitional pricing approach, the AER required that Endeavour transition the demand charge to LRMC over a 10 year period.[267] It is also relevant to note that the AER also approved Ausgrid's introductory demand tariff, where customers are assigned to a less cost reflective variant of their demand tariff for a period of 12 months. We consider that both approaches can be appropriate way to manage the transition to cost reflective pricing depending on the circumstances of the distributors.

Assessment criteria:

We consider that it is necessary for distributors, particularly in the early stages of the tariff reform process to support the introduction of cost reflective pricing with appropriate transitional mitigation measures such as a 12 month grace period or equivalent transitional arrangements.

Location based pricing has significant advantages

In the current environment, we consider that time of use energy tariffs and demand tariffs best balance cost reflectivity[268] with customers' ability to understand tariffs[269] for

[266] Endeavour Energy is currently transitioning the peak demand charge of its default demand tariff for residential and small business customers to LRMC over a ten year period.

[267] AER, *Final Decision - Endeavour Energy - Attachment 18 - Tariff Structure Statement*, April 2019.

[268] NER, cll. 6.18.5(e)(f) and (g).

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

the broad range of customers facing default tariff assignment. However, there are ways to make tariffs more cost reflective, including:

- narrow the peak – in 2013, the Productivity Commission found that in NSW peak demand events occur for less than 40 hours per year and are the key driver for network costs.[270]
- vary by location – distribution networks are made up of many feeder and substation zones. Each zone has its own capacity (or rating), with different load profiles and climates. Therefore, varying tariffs by location can better target the times and locations to signal conservation, indeed in areas with high excess capacity it may be more efficient to encourage usage.

The distribution pricing principles under the NER require that distributors base their proposed tariffs on long run marginal cost, including consideration of:

- times of greatest utilisation of the relevant part of the distribution network.[271]
- the extent to which costs vary between different locations.[272]

Therefore, if distributors were to propose critical peak pricing or prices that vary by location, there is scope for us to approve a tariff structure of this kind as long as they also demonstrate that their proposal satisfies the customer impact principle in the NER.

Assessment criteria:

We consider that it is appropriate for distributors to introduce highly cost reflective tariffs, such as local-specific dynamic peak tariffs to customers on an opt-in basis only.

The need for innovative tariffs depends on retailers

There are numerous tariff structures that distributors could propose to increase cost reflectivity without compromising the customer's ability to understand tariffs. We consider that innovative tariffs have the potential to benefit consumers when they are designed in accordance with efficiency principles. However, in a first-best situation retailers would develop the innovative tariffs based on more standard network tariff structures as a way to reduce the risks of prescribed network tariffs, for example:

- where distributors charge a demand tariff, retailers could develop demand subscription tariffs. In this approach, the distributor charges the retailer a cost reflective demand tariff, and the retailer offers customers demand subscription

270 Productivity Commission, *Electricity Network Regulatory Frameworks,* 9 April 2013, p. 16.
271 NER, cl. 6.18.5(f)(2).
272 NER, cl. 6.18.5(f)(3).

packages, similar to mobile phone offers. The retailer could charge for greater demand than the package

- where distributors charge a critical peak prices, retailers could develop peak rebates.[273] In this approach, the distributor charges the retailer a critical peak price, and the retailer charges all customers a premium assuming normal demand during the critical peaks. Customers that reduce their usage during the critical peak would receive discounts, rewards or cash.

However, we recognise at present most retailers are directly passing through network tariff structures. We would consider innovative network tariff solutions, just like any other tariff, as part of proposed tariff structure statements in the future.

Assessment criteria:

We consider the role of retailers in our assessment of distributor tariff reform proposals

Accumulation meters require anytime charges

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

This requires an anytime charge, where the cost of using electricity does not change based on the time of the day, day of the week or month of the year. The tariff designs proposed by distributors for customers with accumulation meters are summarised in Table B. below.

Table B.3 Anytime charges for accumulation meters by selected distributor

Distributor	Residential customers	Business customers
Ausgrid	Flat tariffs	Flat tariffs
Endeavour Energy	Flat tariff	Inclining block tariff
Essential Energy	Flat tariff	Flat tariff

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

Evoenergy	Flat tariff	Inclining block tariff
Power and Water	Flat tariff	Flat tariff
TasNetworks	Flat tariff	Flat tariff

Source: AER analysis.

We consider that flat tariffs are better to inclining block tariffs. The costs of providing network services do not increase in line with the quantity of electricity consumed (in kWh) over a year. Inclining block tariffs offer no improvements in cost reflectivity, and are more difficult to understand. So we consider that distributors should charge customers on accumulation meters flat tariffs, except in the limited cases where the inclining block tariff has been demonstrated to support the transition of customers to more cost reflective tariffs.

Assessment criteria:

We consider flat anytime tariffs are cost reflective for customers with basic accumulation metering unless a distributors can demonstrate that an inclining block tariff is necessary to minimise the transaction costs associated with assigning or reassigning large users to more cost reflective tariffs.

Large business should face highly cost reflective tariffs

Until this point, we have focused on tariff designs for residential and small business customers. The same NER pricing objective and principles apply to large businesses. However, we can expect large business customers are better placed to understand more complex tariff designs. Large business customers consume much more electricity which motivates large customers to understand their bills. This means that large business customers are better placed to understand more complex cost reflective tariffs compared to small business and residential customers.

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

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

The default tariff designs proposed by distributors for large customers are summarised in Table below.

Table B.4 Large customer tariffs by selected distributor

	Low voltage	High voltage	Sub-transmission
Ausgrid	Annual capacity tariff (both c/kW/day and c/kVA/day) with time of use energy	Annual capacity tariff (c/kVA/day only) with time of use energy	Annual capacity tariff (c/kVA/day only) with time of use energy
Endeavour Energy	Seasonal maximum demand tariff with time of use energy	Seasonal maximum demand tariff with time of use energy	Seasonal maximum demand tariff with time of use energy
Essential Energy	Time of use demand tariff with time of use energy	Time of use demand charge with time of use energy	Time of use demand charge with time of use energy
Evoenergy	Maximum demand tariff with flat energy	Maximum demand tariff with time of use energy and annual capacity charge	Not applicable
Power and Water	Maximum demand tariff with flat energy	Maximum demand tariff with flat energy	Not applicable
TasNetworks	Time of use demand tariff with flat energy charges	Capacity tariff with time of use energy	Not applicable

We consider most of these tariff structures for large business customers are appropriate at this stage, however, we consider it is important that tariff structures become more cost reflective over time.

We encourage distributors to propose more cost reflective tariffs for large customers, such as location based critical peak pricing or rebates on an opt-in basis.[274] These customers should be able to understand these tariffs and may find such tariffs beneficial if they are able to reduce their usage during critical peak events.

Additionally, most distributors provide individually calculated tariffs for some high voltage and sub-transmission customers. We consider that distributors should provide, in their Tariff Structure Statements, how they will calculate those individually calculated tariffs. This additional transparency provides:

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

Distributors should provide in their tariff structure statements a description of how they propose to set their individually calculated tariffs during the next regulatory control period and demonstrate that this approach complies with the pricing principles in the NER. This will ensure that the AER is able to confirm that the proposed prices, as set

[274] SP AusNet offers critical peak pricing to large business customers on an opt-in basis. For more information see:https://www.ausnetservices.com.au/Business/Electricity/Demand-Management/Critical-Peak-Demand-Tariff

out in their annual pricing proposals for these tariffs are consistent with the methodology in the final tariff structure statements.

Assessment criteria:

We consider that distributors currently assign large business customers to cost reflective tariffs and encourage distributors to clearly explain in their tariff structure statements how they propose to set the price levels of these tariffs during the regulatory control period.

Is consistency important between distributors?

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

- cost reflectivity – the cost drivers for most distribution businesses are generally the same, therefore to design a tariff that is cost reflective it is likely that the tariffs may need to be similar
- ability of customers to understand electricity charges - most customers only spend a small proportion of their time considering how their retailer calculates their electricity bill. Having consistent tariff designs, if that flows through to retail tariff design, may make it easier for Governments, distributors and retailers to help customers understand their bills.

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

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

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

Assessment criteria:

We consider that consistency between distributors is desirable where the economic benefits outweigh the economic costs, noting that distributors often need to design their network tariffs to reflect their unique circumstances.

C Long run marginal cost

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

Background

When tariffs accurately reflect the marginal, or forward-looking, cost of increasing (or decreasing) demand, consumers can make informed choices about their electricity usage. Under such tariffs, customers would increase their use of the network only when they value it more than the costs. This in turn signals to distributors to invest in additional capacity to the extent that customers value it.[275]

LRMC is equivalent to such forward looking costs—more specifically, as measured over a period of time sufficient for all factors of production to be varied.[276] LRMC could also be described as a distributor's forward looking costs that are responsive to changes in electricity demand. This could include investment in additional network capacity to service growing peak demand.[277] As we discuss below, this could also include replacement of fixed assets at the end of their economic life where changes in demand is a consideration.

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

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

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

Note on LRMC, residual costs and approach to tariff setting

The rules require network tariffs to be based on LRMC.[278] However, not all of a distributor's costs are forward looking and responsive to changes in electricity demand. For example, distributors may need to replace network assets when they are old and/or have deteriorating condition. Hence, if network tariffs only reflected LRMC, distributors would not recover all their costs. Costs not covered by a distributor's LRMC are called 'residual costs'. The rules require network tariffs to recover residual costs in

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

276 NER, chapter 10 Glossary.

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

278 NER, cl. 6.18.5(f).

a way that minimises distortions to the price signals for efficient usage that would result from tariffs reflecting only LRMC.[279] This appendix sets out our assessment framework. We also outline some principles in our assessment of the approach the distributor used to set tariff levels in pricing proposals—including how it considered LRMC estimates to set such tariffs and how it allocates residual costs.[280]

Assessment approach

This is the second tariff structure statement round for the electricity distribution businesses undergoing a distribution determination.[281] In this round, we are assessing the extent to which a distributor made improvements to its methods for estimating LRMC compared to the first tariff structure statement round. In particular, we assessed whether a distributor:

- investigated the inclusion of replacement capex (repex) in their LRMC calculations[282]
- used a minimum of 10 years of forecast data in the calculation of LRMC[283]
- continued to refine their methods for estimating LRMC so their tariffs better reflect efficient costs.[284]

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

Importantly, we consider these criteria allow us to assess the extent to which a distributor has progressed tariff reform as envisioned in the rules, particularly the requirement that a distributor's method(s) of calculating LRMC has regard to:[285]

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

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

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

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

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

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

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

285 NER, cl. 6.18.5(f).

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

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

We discuss each of our criteria in more detail below.

Inclusion of repex in LRMC estimates

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

> **Assessment criteria:**
>
> We consider whether repex (or any other types of capex) that a distributor includes in its LRMC estimates should meet the definition of 'marginal cost'—that is, the cost of an incremental change in demand.
>
> Where a distributor has not included repex in their LRMC estimates, it must demonstrate why it does not have any forecast repex that can be considered as a 'marginal cost'.

In our final decision for the first tariff structure statement round, we noted the rules define LRMC as the cost of an incremental change in demand over a period of time in which all factors of production can be varied.[286] In the long run, the level of capacity in a distribution network is a variable factor of production. When assets come to the end of their useful life, distributors have a choice of maintaining their current level of capacity, increasing capacity or decreasing capacity, depending on demand and use of the network. Distributors should not adopt a default position of maintaining existing capacity levels, especially where existing networks have spare capacity and where there are changing patterns of use. We considered LRMC estimates should include replacement capital expenditure and associated operating expenditure. This would promote network capacity in the long run at levels consumers' value.[287]

We also noted not all types of repex should be included in LRMC estimates.[288] Marginal cost refers to the cost of an incremental change in demand.[289] Not all repex is

[286] NER, chapter 10—Glossary.

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

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

[289] NER, chapter 10 (definition of long run marginal cost).

associated with an incremental change in demand. For example, we consider repex driven purely by asset condition would not be included in LRMC estimates.

If a distributor includes repex that is consistent with the definition of marginal cost, the next step is assessing whether it has incorporated such expenditure appropriately into its LRMC estimation method. We assess a distributor's incorporation of repex into its estimation method on a case by case basis. This is because we acknowledge LRMC estimates have not traditionally included repex in the context of Australian network regulation. We consider this second tariff structure statement round provides distributors (and other stakeholders, including the AER) with the opportunity to explore and test this aspect of LRMC estimation. Indeed, distributors have proposed several viable methods for incorporating repex into their LRMC estimates in this second tariff structure statement round.[290]

Definition of 'long run'

In our final decision for the first tariff structure statement round, we noted distributors have typically used timeframes of between 10 and 40 years to estimate long run marginal costs. We considered this timeframe captures the essence of 'long run'.[291]

Assessment criteria:

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

The rules define long run marginal costs as the cost of an incremental change in demand over a period of time in which all factors of production can be varied.[292]

In the long run, the level of capacity in a distribution network is variable. Accordingly, the 'long run' would match the life of the assets. Some distribution network assets have very long lives (in excess of 60 years). However, it would be impractical to produce accurate forecasts over such a long horizon. The longer the estimation period, the more difficult it becomes to estimate and forecast long run costs.[293]

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

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

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

292 NER, chapter 10.

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

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

LRMC estimation methods

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

- made improvements to their application of the Average Incremental Cost approach;[294] and/or
- explored the use of other estimation methods, such as the Turvey approach.

<u>Assessment criteria:</u>

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

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

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

In the first tariff structure statement round, all distributors in the NEM used the Average Incremental Cost approach to estimate LRMC, which we accepted. We encouraged distributors to continue improving their estimation methods so their tariffs better reflect efficient costs. This may entail modifying the Average Incremental Cost approach, or utilising more sophisticated approaches, such as the Turvey approach if they consider it appropriate.[295]

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

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

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

Conversely, the Turvey approach is more costly to implement than the Average Incremental Cost approach, but is perceived or is in principle capable of producing estimates that better represent LRMC.[296]

Of course, distributors are not limited to using the Average Incremental Cost approach or the Turvey approach. Indeed, there are several versions and interpretations of the aforementioned approaches.[297]

A key question in our assessment (and for distributors in making their tariff structure statement) is whether the benefits of more accurate estimates of LRMC outweigh the costs of deriving them.[298] This cost-benefit equation will depend on the circumstance of each business.

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

- **Penetration of interval meters**—There is currently low penetration of interval or more advanced (smart) meters in most jurisdictions. This implies distributors can assign a relatively low proportion of customers to cost reflective tariffs (which should signal LRMC).[299] The principal benefit of cost reflective pricing is that customers' use of the network reflects the value they derive from such use. This would then provide the signal to distributors to efficiently invest in the network.[300]

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

- **Postage stamp pricing**— Distributors charge customers the same tariffs across their networks (except for a small number of bespoke tariffs offered to the distributor's largest customers). However, the marginal costs of distribution vary by location, based on the rate of change in demand and level of congestion within the substation or feeder zone (as well as temporal factors).[301] Accordingly, basing tariffs on an estimate of average LRMC or a part of the network's LRMC sends inefficient price signals to most, if not all, customers.

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

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

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

299 Such as demand charges or time of use charges.

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

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

Postage stamp pricing is less costly and simpler to administer for distributors and retailers than locational pricing.[302] It is also arguably more equitable for many end customers. It is therefore unclear the extent to which the industry would, or could, move away from postage stamp pricing in future tariff structure statements. We are not expecting any substantive move by distributors to move towards location-based pricing in this round of tariff structure statements.

Note on the transition to marginal cost pricing

For many distributors, the levels of their cost reflective tariffs differ from their LRMC estimates. This is a legacy of previous practices, when the requirement to consider LRMC was much lower than the current version of the rules.[303] Distributors are transitioning their tariffs toward their LRMC estimates having regard to customer impacts.[304]

Broadly, there are two transitions to marginal cost pricing: 'from above' where the levels of their cost reflective charging parameters[305] are higher than their LRMC estimates; or 'from below' where their cost reflective charging parameters are lower than their LRMC estimates.

In the former, their cost reflective charging parameter contains residual costs on top of the signal of future costs. The transition towards the LRMC estimates, therefore, involves re-allocating residual costs to other tariff parameters such as the fixed charge or a non-time-varying consumption charge (if present). The re-allocation should ensure there is minimal distortion to the efficient price signal.[306]

In the latter, the cost reflective charging parameter currently sends a muted signal of future costs. The distributor would therefore increase the cost reflective charging parameter towards the LRMC estimate while having regard to customer impact.[307]

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

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

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

304 NER, cl. 6.18.5(h).

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

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

307 NER, cl. 6.18.5.

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

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

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

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

Future directions

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

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

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

As required by the NER, we will be mindful of the costs and benefits of improving LRMC estimation methods in our assessment of future tariff structure statements.[308] In the sections above, we acknowledged several factors in the current stage of tariff reform that may limit the benefits of using more sophisticated estimation methods such as the Turvey method.

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

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

  However, the AEMC's metering rule change took effect from 1 December 2017. This should promote increasing penetration of interval meters in the NEM.[309] Distributors should monitor the rate of interval meter penetration and consider the extent to which it can accelerate tariff reform in the third tariff structure statement round. This includes considering the benefits to distributors and its customers of deriving (and signalling) more accurate estimates of LRMC.

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

  The higher costs of more accurate methods to estimation LRMC may be justifiable where a distributor proposes tariffs that send locational signals of congestion. In future tariff structure statement rounds, a distributor may experiment with using such methods if it proposes to trial tariffs in particular areas of its network, for example.[310]

  Also, having regard to location when estimating LRMC does not require a distributor to actually apply location-based pricing. In this second tariff structure statement round, for example, Endeavour Energy produced two separate LRMC estimates: one for areas of stable or decreasing demand, and another for areas of

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

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

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

increasing demand. However, Endeavour Energy still proposed to apply postage stamp pricing for the 2019–24 regulatory control period.[311]

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

We consider this is consistent with the rules requirement that LRMC estimates have regard to the extent to which costs differ between locations (without actually applying locational pricing).[312] It also provided Endeavour Energy with further information regarding the appropriate LRMC estimate on which to base its prices.[313]

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

Distributors may use different estimation methods to account for different types of marginal costs. Ausgrid did so in this second tariff structure statement round to measure the different contributions to LRMC of augmentation capex and replacement capex.[314] Distributors may use different estimation methods, where one method acts as the 'primary' estimation method, while a second method acts as a 'sanity check'. Or, distributors may use different estimation methods to derive a range for LRMC, rather than point estimates, as Ausgrid did in this second tariff structure statement round.[315]

On a final note, we propose consulting with distributors more regularly outside of the distribution determination process on progressing LRMC estimation methods. This is consistent with a suggestion from Energy Networks Australia in the first tariff structure statement round who stated the industry should devote resources to improve the estimation of LRMC.[316] We consider progressing estimation methods for LRMC is an area that could benefit from collaboration and knowledge-sharing between distributors

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

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

313 NER, cl. 6.18.5(f).

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

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

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

and other stakeholders. This could spread the costs of developing more accurate estimation methods, while maximising the benefits of efficient price signals.

D Assigning retail customers to tariff classes

This appendix sets out our draft determination on the principles governing assignment or reassignment of Ergon Energy's retail customers for direct control services.[317] We approve Ergons procedures for assigning and reassigning retail customers to tariff classes.

Procedures for assigning and reassigning retail customers to tariff classes

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

Assignment of existing retail customer to tariff classes at the commencement of the 2020–25 regulatory control period

1. Ergon Energy's customers will be taken to be "assigned" to the tariff class which Ergon Energy was charging that customer immediately prior to 1 July 2020 if:

   (a) they were a Ergon customer prior to 1 July 2020, and

   (b) they continue to be a customer of Ergon as at 1 July 2020.

Assignment of new retail customers to a tariff class during the 2020–25 regulatory control period

2. If, from 1 July 2020, Ergon becomes aware that a person will become a customer of Ergon Energy, then Ergon Energy will determine the tariff class to which the new customer will be assigned.

3. In determining the tariff class to which a customer or potential customer will be assigned, or reassigned, in accordance with paragraphs 2 or 5, Ergon Energy will take into account one or more of the following factors:

   (c) the nature and extent of the customer's usage

   (d) the nature of the customer's connection to the network

   (e) whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

4. In addition to the requirements under paragraph 3, Ergon Energy, when assigning or reassigning a customer to a tariff class, will ensure the following:

   (f) that customers with similar connection and usage profiles are treated on an equal basis

   (g) those customers who have micro–generation facilities are treated no less favourably than customers with similar load profiles but without such facilities.

317 NER, cl. 6.12.1(17).

Reassignment of existing retail customers to another existing or a new tariff class during the 2020–25 regulatory control period

5. Ergon Energy may reassign an existing customer to another tariff class in the following situations:

   (h) Ergon Energy receives a request from the customer or customer's retailer to review the tariff to which the existing retail customer is assigned; or

   (i) Ergon Energy considered that:

      i. an existing customer's load characteristics or connection characteristics (or both) have changed such that it is no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned, or

      ii. a customer no longer has the same or materially similar load or connection characteristics as other customers on the customer's existing tariff, then Ergon may reassign that customer to another tariff class.

Notification of proposed assignments and reassignments and rights of objection for standard control services

6. Ergon Energy must notify the customer's retailer in writing of the tariff class to which the customer has been assigned or reassigned, prior to the assignment or reassignment occurring.

7. A notice under paragraph 6 above must include advice informing the customer's retailer that they may request further information from Ergon Energy and that the customer or customer's retailer may object to the proposed reassignment. This notice must specifically include:

   (j) a written document describing Ergon Energy's internal procedures for reviewing objections, if the customer's retailer provides express consent, a soft copy of such information may be provided via email

   (k) that if the objection is not resolved to the satisfaction of the customer or customer's retailer under Ergon Energy's internal review system within a reasonable timeframe, then, to the extent resolution of such disputes are with the jurisdiction of an Ombudsman or like officer, the customer or customer's retailer is entitled to escalate the matter to such a body

   (l) that if the objection is not resolved to the satisfaction of the customer or customer's retailer under Ergon Energy's internal review system and the body noted in paragraph 7(b) above, then the customer or customer's retailer is entitled to seek a decision of the AER via the dispute resolution process available under Part 10 of the NEL.

8. If, in response to a notice issued in accordance with paragraph 6 above, Ergon Energy receives a request for further information from a customer or customer's retailer, then it must provide such information within a reasonable timeframe. If Ergon reasonably claims confidentiality over any of the information requested by the customer or customer's retailer, then it is not required to provide that information to the customer or customer's retailer. If the customer or customer's

retailer disagrees with such confidentiality claims, he or she may have resort to the complaints and dispute resolution procedure, referred to in paragraph 7 above (as modified for a confidentiality dispute).

9. If, in response to a notice issued in accordance with paragraph 6 above, a customer or customer's retailer makes an objection to Ergon Energy about the proposed assignment or reassignment, Ergon must reconsider the proposed assignment or reassignment. In doing so Ergon must take into consideration the factors in paragraphs 3 and 4 above, and notify the customer or customer's retailer in writing of its decision and the reasons for that decision.

10. If an objection to a tariff class assignment or reassignment is upheld by the relevant body noted in paragraph 7 above, then any adjustment which needs to be made to tariffs will be done by Ergon Energy as part of the next network bill.

11. If a customer or customer's retailer objects to Ergon' tariff class assignment Ergon Energy must provide the information set out in paragraph 7 above and adopt and comply with the arrangements set out in paragraphs 8, 9 and 10 above in respect of requests for further information by the customer or customer's retailer and resolution of the objection.

Notification of proposed assignments and reassignments and rights of objection for alternative control services

12. Ergon Energy must make available information on tariff classes and dispute resolution procedures referred to in paragraph 7 above to retailers operating in Ergon' distribution area.

13. If Ergon Energy receives a request for further information from a customer or customer's retailer in relation to a tariff class assignment or reassignment, then it must provide such information within a reasonable timeframe. If Ergon Energy reasonably claims confidentiality over any of the information requested, then it is not required to provide that information. If the customer or customer's retailer disagrees with such confidentiality claims, he or she may have resort to the dispute resolution procedures referred to in paragraph 7 above, (as modified for a confidentiality dispute).

14. If a customer or customer's retailer makes an objection to Ergon Energy about the proposed assignment or reassignment, Ergon Energy must reconsider the proposed assignment or reassignment. In doing so Ergon Energy must take into consideration the factors in paragraphs 3 and 4 above, and notify the customer or customer's retailer in writing of its decision and the reasons for that decision.

15. If an objection to a tariff class assignment or reassignment is upheld by the relevant body noted in paragraph 7 above, then any adjustment which needs to be made to tariffs will be done by Ergon Energy as part of the next network bill.

System of assessment and review of the basis on which a retail customer is charged

16. Where the charging parameters for a particular tariff result in a basis charge that varies according to the customer's usage or load profile, Ergon Energy will set out

in its pricing proposal a method of how it will review and assess the basis on which a customer is charged.

E Distributors' customer consultation and customer impact analysis

This appendix details the Queensland distributors’ consultation process and comments on their customer impact analysis as outlined in their tariff structure statements.

Customer consultation

We consider that there is scope for the Queensland distributors' to improve their customer consultation by providing greater clarity over the 'problem' that tariff reform is trying to solve and clearly explaining how each element of the tariff reform proposal contributes to addressing this issue.

Energy Queensland undertook stakeholder consultation on the TSS proposal for both Energex and Ergon Energy.

This consultation process consisted of:

- One-to-one interviews with key tariff stakeholders involved in the TSS development process;
- Release and distribution for comment of a TSS related material;
- Numerous TSS stakeholder forums;
- comments and submissions from Have Your Say online portal hosted by the Queensland distributors;
- Social media dialogue and feedback; and
- QLD distributors’ engagement with customer consultative committees, Local Government Areas, other stakeholder groups.

The stakeholder submissions to the AER Issues paper were critical of the Queensland distributors’ TSS consultation process. The range of concerns raised by stakeholders is summarised in the table below.

Table E.1 Key issues and concerns raised by QLD stakeholders

Key Issues raised in submissions	Stakeholders
Insufficient customer impact analysis	QCOSS, ECA, CCP14, QLD Farmers Federation and Queenslanders with disability network
Inadequate customer support/mitigation measures (including education)	QCOSS, ECA, CCP14, QLD Farmers Federation and Queenslanders with disability network
Not properly considered non-tariff solutions	QCOSS, CCP14, ECA and Queenslanders with disability network
Unclear rationale for tariff reform	QCOSS, ECA, CCP14, QLD Farmers Federation, Origin Energy, Total Environment Centre, Red Energy and

Key Issues raised in submissions	Stakeholders
	Queenslanders with disability network
Need for research	QCOSS, ECA, CCP14, QLD Farmers Federation and Queenslanders with disability network
Concern over complexity of proposed tariffs	QCOSS, ECA, CCP14, QLD Farmers Federation and Queenslanders with disability network
Concern for customers on retail transitional tariffs	QLD Canegrowers. QLD Farmers Federation, CCP14 and ECA
Poor quality TSS engagement	QCOSS, ECA, CCP14, QLD Farmers Federation, Origin Energy, Red Energy and Queenslanders with disability network
Incomplete TSS proposal	QCOSS, CCP14, ECA, Red Energy

Source: AER analysis.

Customer impact analysis

We consider the Queensland distributors could improve their customer impact analysis by including all their tariffs in their customer impact analysis and by extending the time period covered by this analysis to include the annual change in network bill over the five years covered by the next regulatory control period.

We also consider that the Queensland distributors could provide stakeholders with more detailed analysis of the potential impact under their proposed tariffs for different customer groups, particularly for irrigators, vulnerable customers and customers with solar PV systems. Stakeholders could also find it valuable if the QLD distributors quantify the extent that different types of customers could mitigate their impact under cost reflective tariffs by taking up control load tariffs.

We note that the Queensland distributors have engaged the UNSW and CSIRO to assist them to undertake disaggregated customer impact analysis of their proposed tariff reforms in the 2020–25 regulatory control period. This should ensure that the Queensland distributors will be well placed to meet the needs of their stakeholders in this regard.